

Forecasts of Future Emissions as Applied to the
Electric Utility Industry

(U.S.) Environmental Protection Agency, Research Triangle Park, NC

Prepared for:

South Carolina Energy Research and Development Center, Clemson

Mar 90



U.S. Department of Commerce
National Technical Information Service

NTIS

TECHNICAL REPORT DATA (Please read instructions on the reverse before completing)		
1. REPORT NO. EPA/600/D-90/024		3. RECIPIENT'S ACCESSION NO. PS 90 220807/AS
4. TITLE AND SUBTITLE Forecasts of Future Emissions as Applied to the Electric Utility Industry		5. REPORT DATE
7. AUTHOR(S) Larry G. Jones		6. PERFORMING ORGANIZATION CODE
9. PERFORMING ORGANIZATION NAME AND ADDRESS See Block 12		8. PERFORMING ORGANIZATION REPORT NO.
12. SPONSORING AGENCY NAME AND ADDRESS EPA, Office of Research and Development Air and Energy Engineering Research Laboratory Research Triangle Park, NC 27711		10. PROGRAM ELEMENT NO.
		11. CONTRACT/GRANT NO. NA (Inhouse)
		13. TYPE OF REPORT AND PERIOD COVERED Published paper; 5/89-3/90
		14. SPONSORING AGENCY CODE EPA/600/13
15. SUPPLEMENTARY NOTES AEERL project officer is Larry G. Jones, Mail Drop 62, 919/541-7716. Presented at Symposium on Energy Futures, Hilton Head, SC, 3/29-30/90.		
16. ABSTRACT The paper discusses forecasts of emissions of sulfur oxides and nitrogen oxides for the electric utility industry to assess the impact of these emissions on the environment and the impacts of additional reductions that have been proposed. The U.S. EPA and the National Acid Precipitation Assessment Program (NAPAP) have each employed emission and cost projection models and have developed a set of model input assumptions for their deployment. The paper compares these alternative model input assumptions and discusses their influence on the projection results of the two primary models in use by EPA (The ICF, Inc. Coal and Electric Utility Model) and by NAPAP (the Advanced Utility Simulation Model).		
17. KEY WORDS AND DOCUMENT ANALYSIS		
a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Pollution Forecasting Sulfur Oxides Nitrogen Oxides Electric Utilities Mathematical Models	Pollution Control Stationary Sources	13B 14G 07B 12A
18. DISTRIBUTION STATEMENT Release to Public	19. SECURITY CLASS (This Report) Unclassified 20. SECURITY CLASS (This page) Unclassified	21. NO. OF PAGES 62 22. PRICE A04

PB90-220807

EPA/600/D-90/024

**FORECASTS OF FUTURE EMISSIONS AS APPLIED TO THE
ELECTRIC UTILITY INDUSTRY**

LARRY G. JONES

U.S. Environmental Protection Agency
Air and Energy Engineering Research Laboratory
Research Triangle Park, North Carolina 27711

Presented to:

SYMPOSIUM ON ENERGY FUTURES
Hilton Head Island, South Carolina
March 29-30, 1990

REPRODUCED BY
U.S. DEPARTMENT OF COMMERCE
NATIONAL TECHNICAL INFORMATION SERVICE
SPRINGFIELD, VA. 22161

Sponsored by:

**SOUTH CAROLINA ENERGY RESEARCH AND DEVELOPMENT CENTER
CONTINUING EDUCATION DIVISION
CLEMSON UNIVERSITY
Clemson, S.C.**

NOTICE

This document has been reviewed in accordance with U.S. Environmental Protection Agency policy and approved for publication. Mention of trade names or commercial products does not constitute endorsement or recommendation for use.

FORECASTS OF FUTURE EMISSIONS AS APPLIED TO THE ELECTRIC UTILITY INDUSTRY

LARRY G. JONES

U.S. Environmental Protection Agency
Air and Energy Engineering Research Laboratory
Research Triangle Park, North Carolina 27711

ABSTRACT

Emissions of sulfur oxides and nitrogen oxides are being forecasted for the electric utility industry to assess the impact of these emissions on the environment and the impacts of additional reductions that have been proposed. The U.S. Environmental Protection Agency (EPA) and the National Acid Precipitation Assessment Program (NAPAP) have each employed emission and cost projection models and have developed a set of model input assumptions for their deployment. This paper compares these alternative model input assumptions and discusses their influence on the projection results of the two primary models in use by the U.S. EPA (the ICF, Inc. Coal and Electric Utility Model) and by NAPAP (the Advanced Utility Simulation Model).

Introduction

Since emission forecasts are dependent upon a large number of input assumptions, can involve thousands of calculations, and are often repeated for alternative scenarios, the use of a computer model to forecast emissions has become a necessity for many government

agencies, research organizations, and private firms. Emission forecasts are dependent upon the assumptions, judgments, and methodologies employed in their preparation. It should not matter to the final result if a forecast is prepared with pencil and paper or with the assistance of a computer model, but to understand a computer model forecast these input assumptions and methodologies must be reviewed. An adequate evaluation of a forecast requires more than an analysis of the implications of a model's output. Understanding model inputs and methodologies and the influence they impart to the forecast, is a necessity for proper interpretation of model results.

Model operations are typically controlled by a series of data files and codes that may or may not be obvious to the model user. Of the four model components listed in Table 1, only the scenario files and the base case input files are specified by the typical model user. The model designer expects the model user to manage or at least specify or approve these inputs for each model run or series of runs. Other inputs contained in data files or methodologies employed in computer code are usually specified by the model developer and are not typically altered between model runs. In some models, these data files or codes may be proprietary or confidential, in some

cases containing cost or other sensitive information provided by non-governmental clients, and may not be made publicly available for peer review by the entire community of model users. Proprietary model files or codes may not be completely opened to inspection by third party reviewers or if opened, the reviewer may be required to keep the information confidential. The model itself may be an important source of revenue for its developer and withheld for release into the public domain for use by any interested party.

One of the objectives of the National Acid Precipitation Assessment Program (NAPAP) has been to ensure that all research products are subjected to peer review. To attain this goal, the Environmental Protection Agency (EPA), in cooperation with NAPAP, has produced a new electric utility emissions control cost and electric rate projection model. This model, the Advanced Utility Simulation Model (AUSM), is independent of proprietary data bases, and is documented.¹⁻¹¹ Early versions of the AUSM model (versions 1.0 and 2.0) were peer reviewed by the Massachusetts Institute of Technology's Energy Laboratory (MIT/EL). These reviews were jointly sponsored by EPA, the Electric Power Research Institute (EPRI), and the Department of Energy (DOE). A later version of the AUSM model (3.0), containing improvements to model

methodologies found deficient by MIT/EL (a doubling of electric generation and emission control technologies and time periods modeled), has been publicly released on magnetic tape to the public.¹² A still later version (4.0), containing additional improvements to model methodologies commented upon by MIT/EL (interstate power transmission constraints were added), is in use by NAPAP for preparation of their base case forecast. An updated version (5.0), recently forwarded to NAPAP, contains codes for use in the analysis of emissions control scenarios that involve the trading of emission allowances among units. Emission allowances are the annual tons of pollutants that may be emitted by a particular unit under a control scenario. Additional reviews of the updated AUSM model by the MIT/EL are planned.

An overview description of the AUSM model methodology is given below. More specific information about the AUSM methodology is given in considerably more detail in published documentation.¹⁻¹¹

AUSM Overview and Description

The Advanced Utility Simulation Model (AUSM) is a computer model designed to provide information to parties interested in participating in the debate accompanying regulation of sulfur oxides (SO_x) and nitrogen oxides (NO_x) from electric utility plants. AUSM provides an

analysis of probable strategies for meeting electric generation load and environmental air emission regulations by state and year for the 48 continental states through the year 2030.

The AUSM model was designed specifically to provide forecasts of future air emissions and the impacts of emissions controls for NAPAP. However, the model is available at cost from the National Technical Information Service (NTIS) for any user who wants to assess the impact of alternative air emissions control strategies on electric utility operations, customer rates, and environmental emissions.¹² The AUSM model has been operated and tested on the EPA's mainframe computer, an IBM 3090 system. The AUSM model is divided into two main programs: the National Loop and the State Model (Figure 1). The AUSM State Model has completed reprogramming and the AUSM National Loop is currently being programmed to operate on a SUN Microsystems, Inc. workstation. This change in computing platform will provide a significantly less expensive mode of AUSM operation for users.

The AUSM National Loop

The National Loop, depicted in Figure 2, consists of MPMS, the Multi-Period, Multi-State module (a utility planning model), and NCSM, the National Coal Supply Module (a coal price projection model). The purpose of the

National Loop is to determine the least-cost strategy of electric generation in future years consistent with the constraints imposed on the industry and the options available to it for power production.

The MPMS module contains 13 separate linear programs (LPs) which determine the demand for coal to meet electric demand in each of the 13 regions which correspond approximately to the North American Electric Reliability Council's (NERC's) power pools (Figure 3). The NCSM module seeks to provide, at the lowest cost, each of the 33 coal types to the 48 state demand regions by considering coal mining and transportation alternatives that are available or that can be constructed. The costs of expanding existing mine production, opening new mines, coal washing, and utilizing alternative coal transportation routes are considered. The future prices of oil and gas fuels are provided by forecasts from an independent model and provided to AUSM by the user. The sum of coal demand by sulfur and coal rank (up to 33 separate coal types) from the 13 regions is then fed to the NCSM which computes the price of each coal type in response to its demand. The NCSM-generated prices of coal, by coal type and year, are fed back to the MPMS module which reanalyzes the utility's operating strategy until

equilibrium is reached. Usually six iterations are required to reach an equilibrium solution.

The MPMS module seeks to minimize the cost of generation consistent with the choices available to it. MPMS seeks to minimize the net present value of the life-cycle costs of electric generation including amortization of capital, and operation and maintenance charges, including fuel costs. Choices are limited by constraints such as generating unit availability, electricity demand by year, interstate electric transmission capability, air emission regulations, peak load generation levels, unit retirement dates, and generating technology types commercially available in a particular year. MPMS is configured to analyze up to 20 different generating technology and emission control alternative combinations. The particular combination of technologies used in each of the 13 regional LPs in the national loop depends upon the types of capacity found in the specific regions. The mix of technologies is user specified and can be altered by time period to allow for the penetration of new electric generating technologies or pollution control devices into the market. The MPMS design allows the model user to choose implementation of new technologies in one of two ways. First, the MPMS module can decide when to bring new technology capacity on-line by using the projected cost of

new technologies, a model input, to choose capacity additions among new and conventional technology choices on a least-cost basis. Secondly, a percentage of the total new capacity constructed by the model to meet demand can be specified by the model user for alternative future time periods. The percentages of new clean coal technologies utilized in each time period are a model input assumption for this alternative mode of model operation. These model inputs must be provided by the model user by an independent analysis of the pace of clean coal technology development and acceptance by the electric utility industry. In addition, repowered units (i.e., those units in which the steam generating unit and in some instances the steam turbine are replaced by a different electric generation technology), can be specifically identified in the unit inventory file and the model will repower units with the technology specified on the scheduled repowering project date.

The National Loop produces files for use by the State Model containing the overall strategy of plant construction and technology selection for meeting electric generating demand and the projected future coal prices. However, the analysis of annual air emissions and costs of control is approximate since the National Loop considers groups of capacity and 5- to 10-year segments of time in

its simulation. The National Loop does not determine impacts on electricity consumers.

The AUSM State Model

The AUSM State Model takes as inputs the coal prices and new plant construction from the National Loop. The AUSM State model provides a more detailed unit-by-unit, state-by-state, year-by-year projection of air emissions and the impacts of emissions control. Using information from the National Loop, the AUSM State Model makes more detailed choices of electric generation and emission compliance strategies without diverging greatly from the strategy developed by the National Loop.

The State Model consists of six basic modules (Demand, Plan, Comply, Dispatch, Impacts, and Finance) that are operated sequentially for each state and for each year (Figure 4). The Demand module computes the amount of capacity to meet the electric demand and reserve margin requirements specified by the AUSM model user. The module also determines electric rates for industrial, commercial, and residential sectors based on revenue requirements.

The Plan module can alter dates of new unit construction by advancing or deferring for a few years the schedule provided by the National Loop and determines the mix of base load and peaking load capacity constructed. The Comply module determines the least-cost strategy of

attaining air emission regulations by examining the cost of compliance for each compliance option and for each available coal type (up to 33). For example, oil and gas switching, hydrated lime injection, wet or dry scrubbing, and switching to low sulfur compliance coals within the same rank are available SO₂ control alternatives. NO_x control alternatives include low excess air, overfire air, and low-NO_x burners. The Comply module computes the variable cost of operation after the least-cost (net present value of unit life-cycle amortization of capital, operating, and maintenance costs) compliance strategy is selected. The variable costs of operations are reported to the Dispatch module, where units are dispatched on a least-cost basis, subject to constraints on the units' minimum and maximum levels of operation. A unit's maximum level of operation is set at an availability limit. The unit's minimum level of operation is set based on spinning reserve and peak load requirements.

The model is also capable of analyzing control scenarios which permit the attainment of unit specified emission reductions by alternative units in the same or other utility systems (i.e., the trading of emission allowances). Total annual emissions are specified for units in a trading scenario (i.e., the annual tons per year of emission allowances). These emission allowances

may be traded (i.e., bought and sold) when advantageous to reduce costs of compliance. The costs of compliance are reduced if the reductions at the alternative unit can be made at a lower cost per ton of pollutant removed.

When emissions trading scenarios are analyzed, an optional code is used to provide a feedback loop from the Dispatch module to the Comply module. This code provides a means of determining the least-cost solution by balancing the cost per ton of SO_x reductions that can be achieved through use of emission control systems or fuel switching with the cost per ton of SO_x reductions that can be achieved by redispatching the units within the utility system. The Comply and the Dispatch modules are each supplied with files containing a state-wide emission ceiling or cap (i.e., tons per year of SO_x) that must be attained for an emission reduction scenario. When operated with a state cap, a least-cost solution for the trading scenario is produced assuming the trading of emission allowances takes place among units within the state (i.e., intrastate trading). The State Model runs are repeated for over-control and under-control levels of the state-wide emission ceiling (e.g., 70, 80, 90, 110, 120, and 130 percent of the state-wide emissions ceiling). These model runs are used to produce marginal cost curves for each state which can then be used to estimate the

potential cost savings of buying and selling of emission allowances between states (i.e., interstate trading).

After the units are dispatched to minimize variable costs of operation, the resulting emissions from the generating units and their total direct costs of operation are summed by the Impacts module. The information is passed to the Finance module which computes the electric utility company's financial statement. Indirect costs are added, and revenue requirements, taxes, cost of capital, and dividends are determined. The costs of capital are dynamic, depending on the financial health of the utility company. This information is passed on to a report writer and to the Demand module where electric rates are determined, and the simulation proceeds for the next year.

Policy Options in AUSM

The current version of the AUSM (5.0) can address the policy options that are central to the current debate over strategies and legislation to reduce SO_x and NO_x from electric generating stations. The model can address the impacts of legislative/regulatory compliance strategies that include:

- o mandated scrubbers at a selected set of units,
- o the establishment of target SO_x and NO_x emission rates for individual stations or sets of stations,

- o the establishment of state or regional emission caps on all units or a subset of generating units in that state/region,
- o the use of an end date provision where all stations reaching a certain age have to either comply with a specified emission limit or be retired,
- o intrastate trading between different units,
- o the use of managed emissions dispatch to achieve emissions reductions targets (this can be a very cost-effective strategy for modest 1 to 4 million ton SO_x reductions), and
- o the impact of different assumptions regarding repowering on compliance costs.

Other policy questions and sensitivity analyses can be performed using different electricity growth rate assumptions, different scrubber cost assumptions, and different unit lifetimes and operating constraints. The policy analysis options that have recently been incorporated into AUSM are designed to address the provisions of legislative proposals that have been considered recently by Congress, based on assumptions concerning the way in which these provisions would be implemented by states and utilities.

Forecasts from the AUSM model, version (5.0) prepared using model inputs selected by NAPAP, and forecasts from the proprietary Coal and Electric Utility Model (CEUM), prepared using model inputs selected by EPA, are presented herein. These forecasts are prepared for scenarios that do not involve revision of current emission standards (i.e., NAPAP and EPA base cases) and for 10 million ton SO_x emissions reduction scenario cases. These forecasts, discussed below, show the major influence of alternative NAPAP and EPA model input parameters on base case and control scenario case results. Although these models, AUSM and CEUM, are not completely alike in methodology, they have previously been shown to produce comparable results on an aggregate level (i.e., national emissions) when inputs are normalized to a common set of parameters.¹¹

Model Input Assumptions

The parameters of primary importance in influencing the forecast results are discussed in this section. In forecasting emissions from the electric utility industry, several types of key parameter inputs are needed which are of necessity also forecasts reflecting expectations of the future. Some of the most important parameters influencing future emissions from the electric utility industry are:

- o electric demand growth,
- o fuel price projections,
- o technological changes in electric generating and pollution control equipment,
- o demand management/cogeneration impacts on utility electric generation, and
- o emission control regulations and laws.

Selection of a single set of these model input parameters for a base case minimizes the number and cost of scenario runs. When two base cases are used, the number of scenario runs is doubled, because one scenario run for each of the base cases is needed to determine the incremental change in emissions or costs relative to the baseline condition. When the proposed strategy involves the use of interstate emissions allowance trading, multiple runs of the AUSM model more and less stringent than the targeted emissions reductions are needed for each baseline condition to determine the marginal costs of emission control in each state and the potential for interstate emissions allowance trading. For these scenarios, doubling of the number of runs can cause a substantial increase in model run activity.

Even though the cost and complexity of producing the forecast may significantly increase, when strong justification has not or cannot be identified for only one

set of model input parameters, more than one set may be considered desirable to bound the influence of the key input parameters. In the most recent set of EPA forecast results, two sets of input parameters were selected to bound the highest and lowest forecasted emissions outputs considered to be reasonable possibilities. For example, the EPA chose a lower (and higher) range of forecasted electric demand and higher (and lower) amounts of repowered capacity, thereby compounding their influence, in producing a "low" (and a "high") emissions forecast. These sets of input parameters are referred to as the EPA High (EPA/H) emissions and EPA Low (EPA/L) emissions base cases. NAPAP has elected to use a single set of model input parameters, referred to as the Analysis Reference Case (ARC), but NAPAP has announced plans to additionally provide a range of sensitivity test case results using alternative model input assumptions.¹³

Model input assumptions used by EPA in the preparation of emission forecasts for the electric utility industry were developed by ICF, Incorporated, and RCG/Hagler Bailly in 1989.^{14, 15} The NAPAP model input assumptions were jointly developed by representatives of DOE and EPA. These assumptions form the ARC and are to be used in preparation of a baseline forecast for the NAPAP Integrated Assessment.¹³ The ARC assumptions were in part

derived from draft projections planned for use in updating the previous National Energy Policy Plan (NEPP) Projections. The NEPP projections were last published by DOE in 1988.¹⁶ Plans to update the NEPP were cancelled, but the draft projections were retained for the ARC. The ARC inputs through the year 2000 are similar in several respects to the Annual Energy Outlook projections published by DOE in early 1989.¹⁷

Electric Demand Growth Rates

Electric demand has changed dramatically since the 1960s when sales grew an average of 7.4 percent per year largely due to increased use of appliances.¹⁷ Between 1975 and 1985 energy use per unit of industrial output declined about 4 percent per year due to higher energy prices and conservation.¹⁶ The rate of energy efficiency improvements is expected to be lower in the future, less than 2 percent per year, but the reduction in demand due to conservation will be more than offset by increased economic activity.¹⁷ Even with increased energy efficiency improvements by residential, commercial, and industrial utility customers, electric demand is forecasted to increase at a steady rate of 2.6 percent between 1988 and 2000 by the Energy Information Administration (EIA).¹⁸ However, NERC projects an "annual net energy for load" for 1988 through

1998 of only 2.0 percent annual growth with an 80 percent probability band of 1.1 to 2.7 percent.¹⁹

The annual growth rate in electric utility generation reached 5 percent in 1988, the highest since 1976, in part due to weather conditions. In comparison to the average cooling degree days for the period 1951 through 1980, the year 1988 was 7 percent warmer.¹⁸ For the year ending February 3, 1990, electric output was reported up 2.9 percent over last year by the Edison Electric Institute.²⁰

The national electric demand growth rates for the EPA and NAPAP base cases (shown in Figure 5) range from 1.4 percent for the EPA/L case (2001 to 2010) to 2.9 percent for the NAPAP/ARC case (1988 to 1995) annual compounded growth. These growth rates are assumed to be net after consideration of the effect of utility demand management conservation programs. Except for the first period, 1988 through 1995, the NAPAP/ARC growth rate falls between the EPA high and low emissions base cases. EPA chose its high emissions case growth rate close to previous (1987) DOE projections and its low growth case is based on higher energy conservation estimates.¹⁵

Gas and Oil Fuel Prices

In the ARC, the future prices of natural gas, distillate oil, and residual oil are specific to each state. In the EPA base cases, fuel prices are specific to

the nine U.S. Census regions (Table 2). Figures 6 through 11 depict the average national oil and gas forecast used for the ARC and the median of the regional oil and gas prices used for the EPA base cases.¹⁵ As shown in Figures 6 through 8, the ARC oil and gas prices are higher than those used by EPA after the year 2000.

The principal fuel switch that could affect emissions from conventional oil and gas steam generating units is between natural gas and high sulfur (2.8 percent) residual oil fuels. The price of distillate oil in each of the three cases is typically higher than natural gas and high sulfur residual oil; therefore, distillate oil use is not an important factor in the forecast.

The EPA base cases favor either natural gas use (EPA/L) or residual fuel oil use (EPA/H). In the low emissions case the price of natural gas has been set lower than the high sulfur residual oil price in the East North Central, East South Central, West South Central, and Mountain Census regions to promote natural gas use, and units in Texas, Louisiana, and California were assumed to consume only gas. Although the EPA low emissions case does have the price of natural gas higher than residual oil in the Pacific and West North Central Census regions, the consumption of residual oil fuels by these units is relatively modest compared to national total residual oil

fuel use. In the ARC case, the price of natural gas is also lower than oil fuels leading to lower emission projections. In the EPA high emissions case, high sulfur residual oil prices are lower than natural gas prices in all regions, leading to higher emissions.

Electric Generation Capacity

Power produced by Independent Power Producer (IPP) capacity is modeled in AUSM and CEUM models as if it were produced by the utilities.¹⁵ Cogenerated power production is an input to CEUM, but not to AUSM. Cogeneration emissions are small, since natural gas is used in many of these facilities.¹⁵ NAPAP is projecting cogeneration facility emissions using the Industrial Combustion Emissions (ICE) Model, a fossil-fuel-fired industrial boiler emissions and cost projection model.²¹

Each of the base cases has fundamentally the same amount of nuclear capacity in its input assumptions through the year 2005, since no new unplanned nuclear capacity is assumed in the forecast. The retirement ages of existing coal-fired units are also similar, 55 years in the EPA/L and ARC base cases and 65 years in the EPA/H case.¹⁵ From 2000 to 2010, 5 percent of total capacity >75 MW reaching 30 to 35 years of age is assumed to retire in the ARC case.¹³ In the EPA base cases, retirements are limited to units <50 MW reaching 45 years of age.¹⁵

The ARC forecast brings on line unplanned coal-fired steam generator capacity after 1996. The EPA base cases defer new unplanned coal-fired capacity until 2000 (EPA/H) and 2005 (EPA/L). Each of the three base cases relies more on new natural gas capacity to meet electric demand for the next 10 years.

Forecast Results

Figure 12 shows the relative amounts of total capacity for each of the three base case forecasts.¹⁴ The capacity outputs of the AUSM and CEUM models are relatively close for the ARC and EPA/H base cases, respectively.

Technological advances in generating equipment are incorporated into each of the base case forecasts, but to a much lesser extent in the EPA base cases. The EPA base case inputs assume a small amount of repowered capacity by 2010 and no significant amount of new advanced coal technology (i.e., integrated coal gasification combined cycle systems, atmospheric fluidized bed combustion units, and pressurized fluidized bed combustion combined cycle units) capacity additions.²² In contrast to the relatively small advanced coal capacity in the EPA/H (7 GW) and EPA/L (25 GW) base cases, the ARC base case has 130 GW of repowered and new advanced coal capacity in 2010. These differences in the amount and types of

capacity additions account for the major differences in emissions between the EPA/H and ARC base case forecasts in the post-2000 period. The proportions of capacity additions that emit low levels of SO_x are very different for these base cases as is shown in Figures 13 through 15. The ARC case (Figure 15) assumes that new Advanced Coal Technologies (ACT) will displace use of conventional, pulverized-coal-fired (PC) boilers in the post-2000 period. In addition, the ARC base case assumes that the new advanced coal technologies will routinely attain more SO_x removal than is required by the current New Source Performance Standards which were last revised in 1979 (RNSPS). The Integrated Gasification Combined Cycle (IGCC) units are assumed to remove 98 percent of SO_x emissions and the Fluidized Bed Combustion (FBC) units are assumed to remove 90 percent of SO_x emissions. Conventional pulverized coal-fired steam generators fitted with flue gas desulfurization systems (PC/FGD) are assumed to attain no greater SO_x removal, 70 to 90 percent, than is required by the RNSPS.

The effect of the alternative input assumptions on emissions is dramatic between the base case forecasts (Figures 16 through 20). Figures 18 through 20 show for each of the base cases the distribution of coal-fired unit SO_x emissions from four categories: pulverized coal (PC)

units subject to State Implementation Plans (PC/SIP) standards, PC units subject to the original New Source Performance Standards promulgated in 1971 (PC/NSPS), PC units subject to the RNSPS (PC/RNSPS), and the advanced coal technology units which are also subject to RNSPS, but are assumed to achieve higher SO_x removal by the ARC. The EPA/H case shows an increasing amount of SO_x emissions through 2010 due in large part to the continued growth of new PC/FGD unit capacity (Figure 19), and very little reduction in SO_x emissions from existing, SIP regulated, coal-fired capacity. In contrast, the ARC case shows substantial reductions in SO_x emissions from existing capacity by 2010 (Figure 18) due to the operation of new IGCC capacity (Figure 15). In the EPA/L case, a relatively modest reduction in existing unit and total SO_x emissions is forecast for 2010 (Figure 20). The ARC case existing capacity SO_x emission results, based on 1980 data, have been reduced by 8 percent (the percent difference between the AUSM projected 1985 emissions and the NAPAP 1985 Emission Inventory data) to reflect an adjustment to SO_x emissions resulting from use of 1980 vintage data in the unit inventory file of the AUSM and from oil to gas switching that took place between 1980 and 1985 not reflected in the AUSM forecast. This adjustment will not be necessary in the future since the AUSM model

unit inventory file has recently been updated with a 1985 data base and algorithms were added to the State Model to provide rules for oil to gas switching.

These base cases illustrate that the model forecasts of emissions are driven in large part by the input assumptions regarding the type and amount of capacity that will be constructed in the future. Given the uncertainty in future cost estimates for developing technologies, NAPAP and EPA have elected to use capacity mix input assumptions developed independently of the forecast model. The amount of IGCC and other developing coal technology capacity actually constructed in future years will depend on many factors including the success in demonstrating the economics and reliability in commercial service of the developing coal technologies in comparison to continued reliance on conventional coal, principally PC/FGD, steam generating equipment. The AUSM model is capable of determining the mix of future capacity on a least-cost basis, but is dependent on the capital and operating cost inputs of the alternative generating technologies for determining the capacity mix.

These results provide support to the view of some analysts that the absolute value of the forecast result is less important than determining the incremental impacts between a base case forecast and an emission control case

scenario in which all inputs other than a change to the emission control requirements are kept constant. This is the usual methodology for determining impacts of proposed revisions to emission control rules. AUSM and CEUM are being employed to examine the effect of a 10 million ton SO_x reduction strategy by the year 2000. The forecast results (Figures 21 through 25) are preliminary for several reasons:

- o the final ARC input assumptions are subject to change because the electric demand and fuel prices model inputs are determined interactively with other models,
- o the final amount of emission reductions and the unit-specific emission allowances that may be required of the electric utility industry have not yet been decided by the Congress.

Emissions Allowance Trading

A key feature of the President's proposed legislation (Title V) to amend the Clean Air Act was the use of emissions allowance trading to produce a more cost-efficient result.²³ Specific units are expected to be given an annual emissions ceiling or allowance, not to be exceeded, which may be attained by alternative units. By buying or selling emission allowances, units with relatively high costs of emissions compliance could avoid

incurring excessive costs (i.e., greater than an average emissions control cost) by buying reductions from a unit that can achieve the required emissions reductions at a lower cost. On the basis of trading (buying and selling) allowances within a utility system, the costs of compliance have been estimated for the EPA base cases (Figure 25). Additional cost reductions are potentially feasible if utility companies are willing to lease or sell credits across state lines. The willingness to trade allowances interstate will be dependent on the availability of emission allowances for trading. Recently proposed revisions to the Clean Air Act legislation would allow EPA to reserve part of the allowances for distribution through auctions.²⁴ This particular proposal, which may or may not become part of the final bill, shows that efforts are being made to amend the final bill intended to enhance the willingness of affected parties to support and participate in the proposed interstate emission trading program.

The projected cost of a 10 million ton reduction (no fees are included) assuming a perfectly free market in emission allowances is shown in Figure 25. As would be expected, the total levelized annual cost of compliance is reduced by system trading and even further reduced by interstate emission allowance trading. The states

projected by the CEUM model where trades may be cost effective to buy or sell are shown in Figure 26 and Table 3.²⁵ Since the majority of trades are confined to the eastern U.S., the effect of trading on acid deposition patterns may not be an important factor.

References

1. J.J. Stukel. Advanced Utility Simulation Model Analytical Documentation, State Level Model (Version 1.0). University of Illinois, Urbana-Champaign, Illinois. EPA-600/8-88-071a. NTIS No. PB 89-161772. Prepared for the U.S. Environmental Protection Agency, Air and Energy Engineering Research Laboratory. Research Triangle Park, North Carolina. January 1989.
2. J.J. Stukel. Advanced Utility Simulation Model Program Documentation, State Level Model (Version 1.0). University of Illinois, Urbana-Champaign, Illinois. EPA-600/8-88-071b. NTIS No. PB 89-166631. Prepared for the U.S. Environmental Protection Agency, Air and Energy Engineering Research Laboratory. Research Triangle Park, North Carolina. January 1989.
3. C.J. Badger and H. Ojalvo. Advanced Utility Simulation Model Documentation of System Design, State Level Model (Version 1.0). University of Illinois, Urbana-Champaign, Illinois. EPA-600/8-88-071c. NTIS No. PB 89-101208. Prepared for the U.S. Environmental Protection Agency, Air and Energy Engineering Research Laboratory. Research Triangle Park, North Carolina. August 1988.
4. R. Edahl, N. Tyle, S. Talukdar, N. Pachavis, and J.J. Stukel. Advanced Utility Simulation Model Multi-Period Multi-State Module Design Documentation (Version 1.0). University of Illinois, Urbana-Champaign, Illinois. EPA-600/8-88-071d. NTIS No. PB 88-204268. Prepared for the U.S. Environmental Protection Agency, Air and Energy Engineering Research Laboratory. Research Triangle Park, North Carolina. April 1988.

5. C.J. Badger and W.H. May. Advanced Utility Simulation Model Operations (Version 1.0). University of Illinois, Urbana-Champaign, Illinois. EPA-600/8-88-071e. NTIS No. PB 89-118749. Prepared for the U.S. Environmental Protection Agency, Air and Energy Engineering Research Laboratory. Research Triangle Park, North Carolina. October 1988.
6. J.J. Stukel. Advanced Utility Simulation Model Data Base Maintenance (Version 1.0). University of Illinois, Urbana-Champaign, Illinois. EPA-600/8-88-071f. NTIS No. PB 88-204276. Prepared for the U.S. Environmental Protection Agency, Air and Energy Engineering Research Laboratory. Research Triangle Park, North Carolina. April 1988.
7. B. Hannon, R. Jackson, and D. Kennedy. Advanced Utility Simulation Model Energy and Employment Impacts Module (Version 1.0). University of Illinois, Urbana-Champaign, Illinois. EPA-600/8-88-071g. NTIS No. PB 89-126569. Prepared for the U.S. Environmental Protection Agency, Air and Energy Engineering Research Laboratory. Research Triangle Park, North Carolina. October 1988.
8. R. Capone. Advanced Utility Simulation Model Description of the National Loop (Version 3.0). Science Applications International Corporation, McLean, Virginia. EPA-600/8-88-071h. NTIS No. PB 89-151468. Prepared for the U.S. Environmental Protection Agency, Air and Energy Engineering Research Laboratory. Research Triangle Park, North Carolina. December 1988.
9. R. Capone, R. Lassinger, C. Peterson, and E. May. Advanced Utility Simulation Model Description of Modifications to the State Level Model (Version 3.0). Science Applications International Corporation, McLean, Virginia. EPA-600/8-88-071i. NTIS No. PB 89-161780. Prepared for the U.S. Environmental Protection Agency, Air and Energy Engineering Research Laboratory. Research Triangle Park, North Carolina. January 1989.
10. R. Capone, E. May, and C. Peterson. Advanced Utility Simulation Model User's Guide (Version 3.0). Science Applications International Corporation, McLean, Virginia. EPA-600/8-88-071j. NTIS No. PB 89-126577. Prepared for the U.S. Environmental Protection Agency, Air and Energy Engineering Research

Laboratory. Research Triangle Park, North Carolina.
October 1988.

11. R. Capone, R. Lassinger, E. May, and C. Peterson. Advanced Utility Simulation Model Report of Sensitivity Testing, Calibration, and Model Output Comparisons (Version 3.0). Science Applications International Corporation, McLean, Virginia. EPA-600/8-88-071k. NTIS No. PB 89-166649. Prepared for the U.S. Environmental Protection Agency, Air and Energy Engineering Research Laboratory. Research Triangle Park, North Carolina. January 1989.
12. E. May. A Mathematical Model of Electric Utility Company Operations - The Advanced Utility Simulation Model (AUSM), Version 3.0 Magnetic tape. Science Applications International Corporation, McLean, Virginia. EPA-600/8-88-071l. NTIS No. PB 89-175608. Prepared for the U.S. Environmental Protection Agency, Air and Energy Engineering Research Laboratory. Research Triangle Park, North Carolina. March 1989.
13. Assessment Plan Update. The National Acid Precipitation Assessment Program, Washington D.C. August 1989.
14. 1989 EPA Base Case Forecasts. ICF, Resources Incorporated, Fairfax, Virginia. May 1989.
15. Background Documentation for 1989 Base Case Forecasts. RCG/Hagler Bailly, Boulder, Colorado. RCG No. 89-9101. June 1989.
16. Long Range Energy Projections to 2010. U.S. Department of Energy, Office of Policy, Planning and Analysis. Washington, D.C. DOE/PE-0082. July 1988.
17. Annual Energy Outlook 1989. U.S. Department of Energy, Energy Information Administration. Washington, D.C. DOE/EIA-0383(89). January 1989.
18. Annual Outlook for U.S. Electric Power 1989. U.S. Department of Energy, Energy Information Administration. Washington, D.C. DOE/EIA-0474(89). June 1989.
19. 1989 Electricity Supply and Demand. North American Electric Reliability Council. Princeton, New Jersey. October 1989.

20. The Energy Daily. Washington, D.C. Vol. 18, No. 31. February 14, 1989.
21. T. Hogan. Description of the Industrial Combustion Emissions Model (Version 6.0). Energy and Environmental Analysis, Inc., Arlington, Virginia. EPA-600/8-88-077. NTIS No. PB 88-212287. Prepared for the U.S. Environmental Protection Agency, Air and Energy Engineering Research Laboratory. Research Triangle Park, North Carolina. May 1988.
22. Telephone Conversation by Larry Jones, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina with Bruce Braine, ICF Resources, Inc., Fairfax Virginia. March 5, 1990.
23. Clean Air Act Amendments of 1989, Section-by-Section Analysis. U.S. Environmental Protection Agency. Office of External Affairs. Washington, D.C. July 1989.
24. Mitchell/Administration Reach Pact on Major CAA Portions, Next Step: The Floor. Inside EPA Weekly Report. Washington, D.C. March 2, 1990.
25. Economic Analysis of Title V (Acid Rain Provisions) of the Administration's Proposed Clean Air Act Amendments (H.R.3030/S.1490). ICF Resources, Inc. Prepared for the U.S. Environmental Protection Agency. Washington, D.C. September 1989.

TABLE 1 MODEL FILE AND CODE COMPONENTS

	MODEL COMPONENT	CHANGE FREQUENCY
A	SCENARIO FILES	EACH RUN
B	BASE CASE INPUT FILES	EACH RUN SERIES
C	STANDARD FILES	EACH MODEL UPDATE
D	STANDARD CODES	EACH MODEL UPDATE

TABLE 2. U.S. CENSUS REGIONS

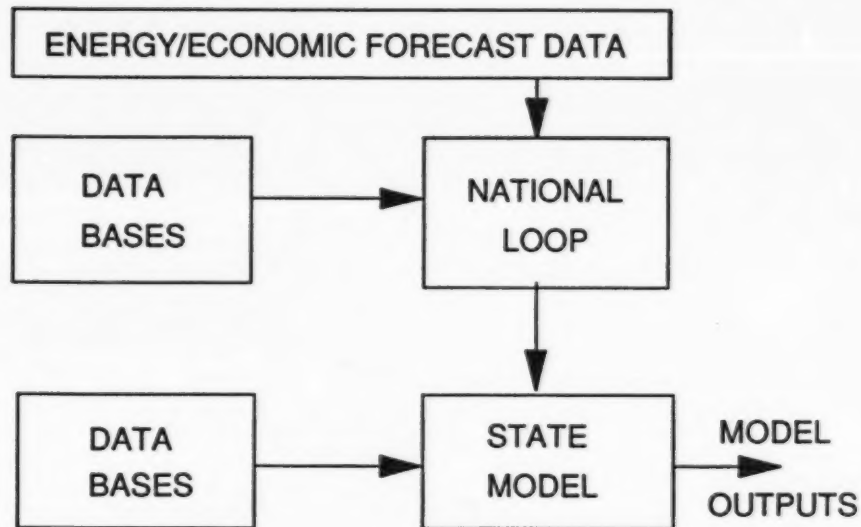
REGION	STATE
NEW ENGLAND	ME,NH,VT,MA,CT,RI
MIDDLE ATLANTIC	NY,PA,NJ
SOUTH ATLANTIC	DE,MD,WV,VA,NC,SC,GA,FL
EAST NORTH CENTRAL	WI,MI,IL,IN,OH
EAST SOUTH CENTRAL	KY,TN,MS,AL
WEST NORTH CENTRAL	ND,SD,NE,KS,MN,IA,MO
WEST SOUTH CENTRAL	TX,OK,AR,LA
MOUNTAIN	MT,ID,WY,UT,NV,CO,AZ,NM
PACIFIC	WA,OR,CA

**TABLE 3 POTENTIAL SO_x EMISSION ALLOWANCE
TRADES IN THE YEAR 2000
(THOUSAND TONS)**

SELLING STATES			BUYING STATES		
STATE	EPA/H	EPA/L	STATE	EPA/H	EPA/L
PA	225	84	NC/SC	120	46
IL	80	125	IN	93	61
AL	60	47	FL	58	39
GA	28	10	KY	46	36
MA/CT/RI	5	48	WV	35	50
OTHER	87	53	OTHER	165	142
EASTERN 31 TOTAL	485	367	EASTERN 31 TOTAL	517	374
WESTERN 17 TOTAL	69	53	WESTERN 17 TOTAL	37	46
NATIONAL TOTAL	554	420	NATIONAL TOTAL	554	420

CEUM MODEL FORECAST

FIG. 1 AUSM MODEL CONFIGURATION



DATA BASES:

- UNIT INVENTORY
- ANNOUNCED UNIT INVENTORY
- FINANCIAL DATA
- COAL RESERVES
- COAL MINING COSTS
- COAL TRANSPORTATION COSTS
- OIL/GAS PRICES
- ELECTRIC DEMAND GROWTH

FIG. 2 AUSM NATIONAL LOOP

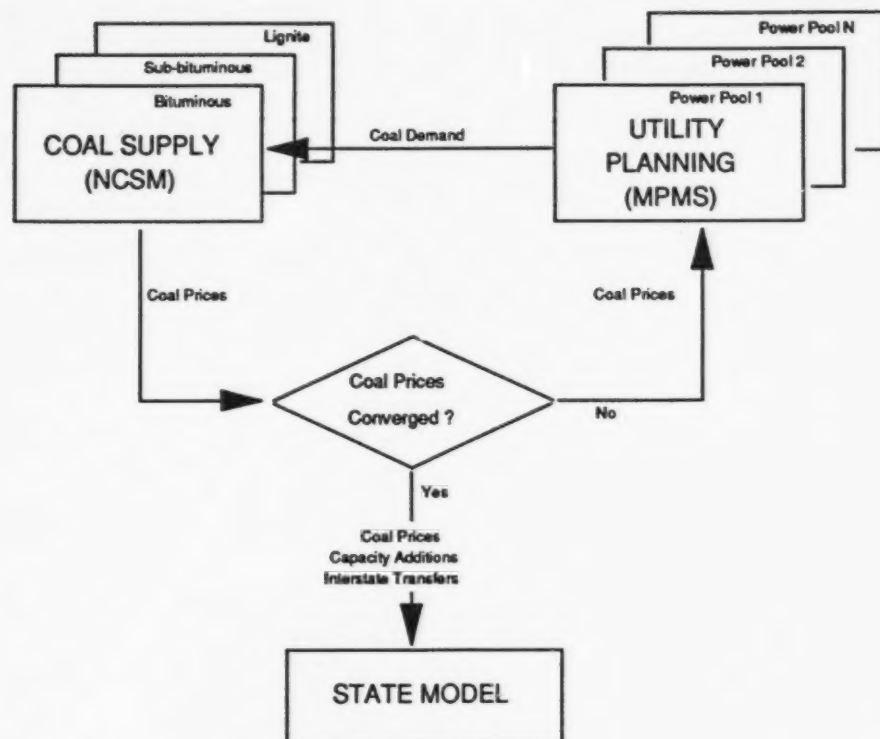


FIG. 3 NATIONAL LOOP REGIONS

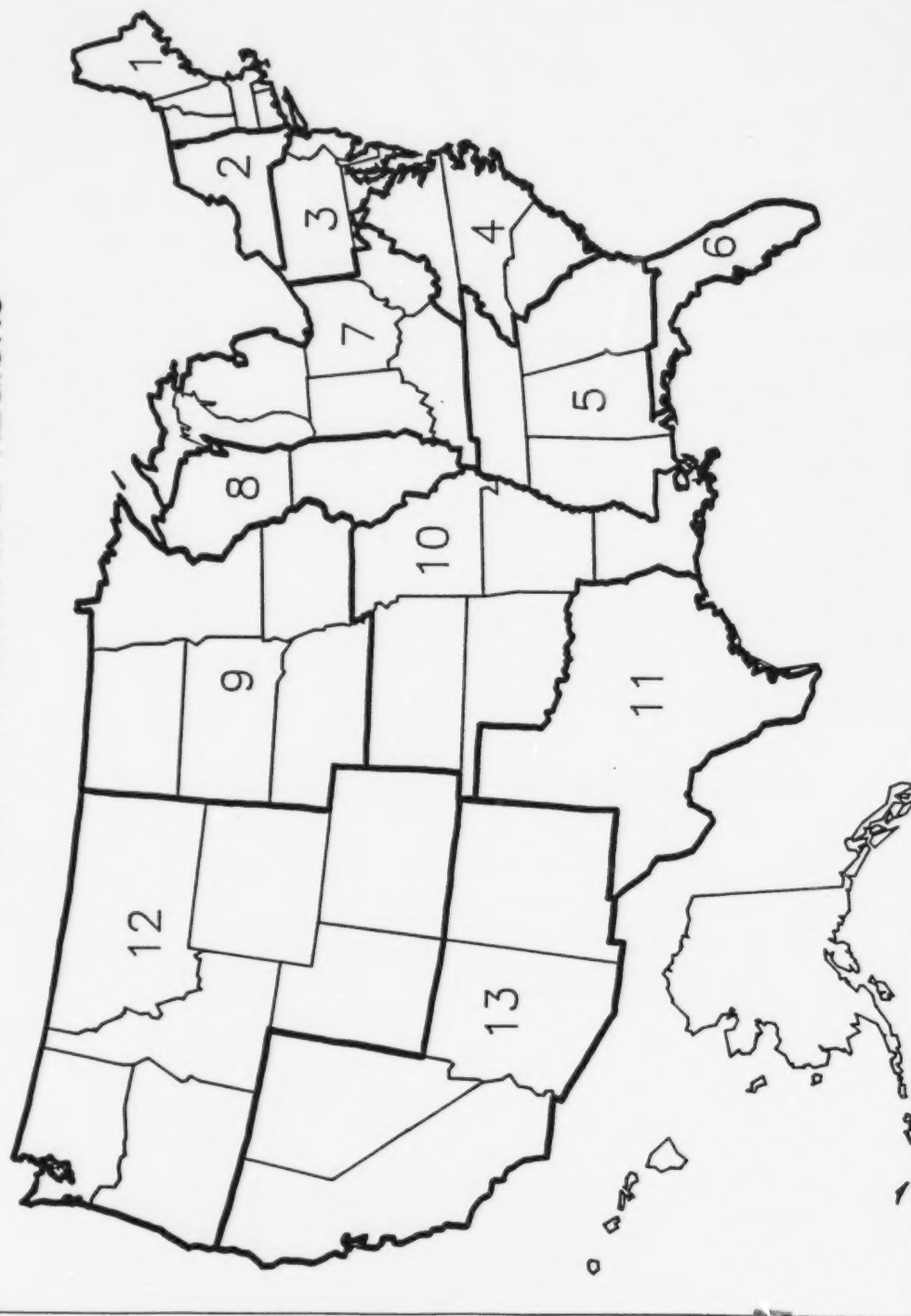


FIG. 4 AUSM STATE MODEL

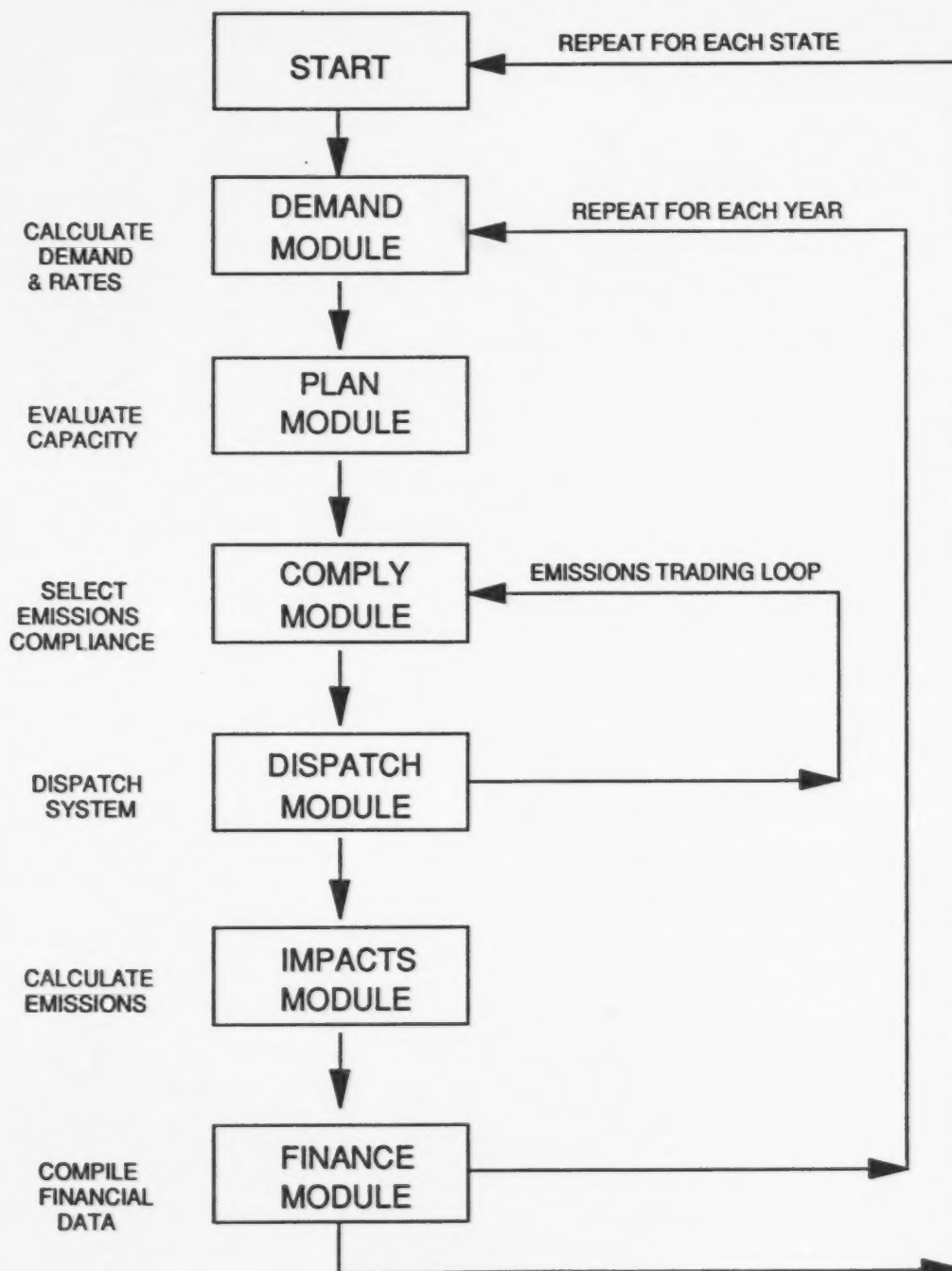
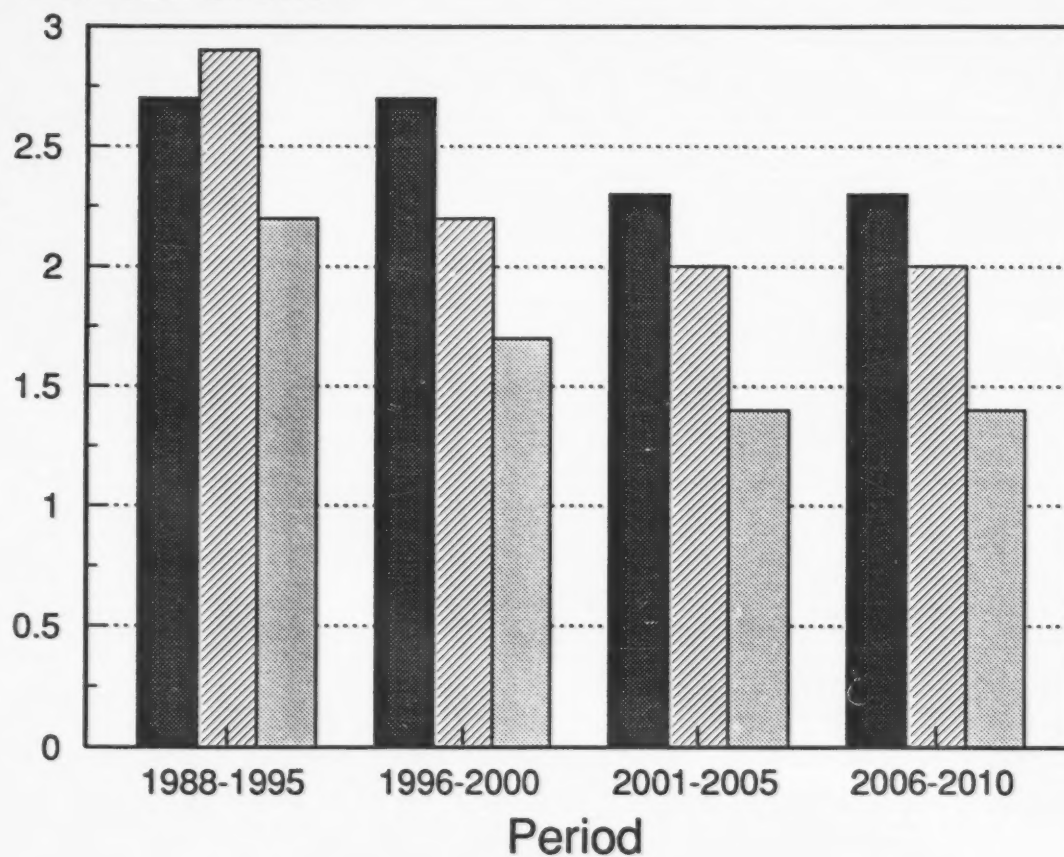


FIG. 5 NATIONAL ELECTRIC DEMAND
COMPOUND ANNUAL GROWTH RATE
MODEL INPUTS

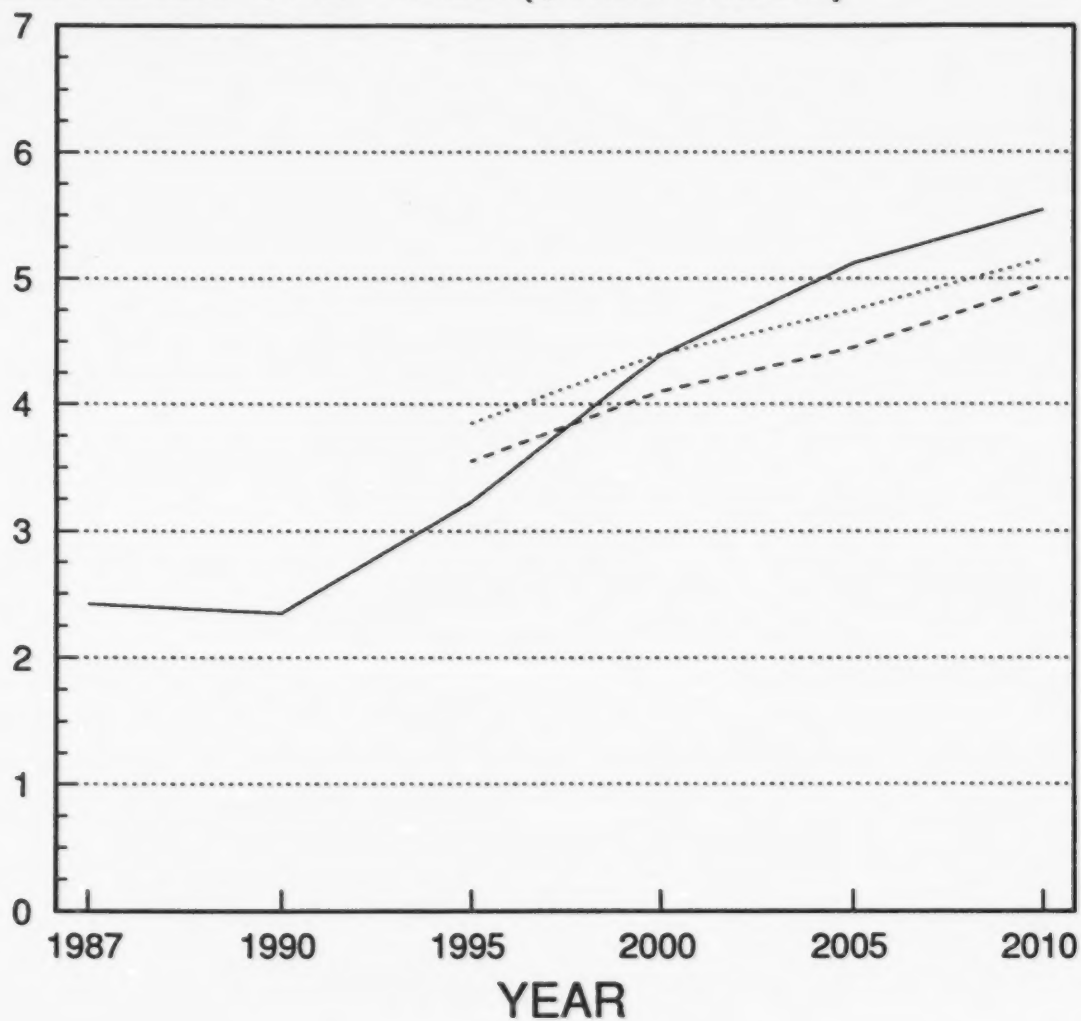
Percent Growth



EPA/HIGH **NAPAP/ARC**
EPA/LOW

FIG. 6 NATURAL GAS PRICE FORECAST
NAPAP/ARC & EPA BASE CASE
MODEL INPUTS

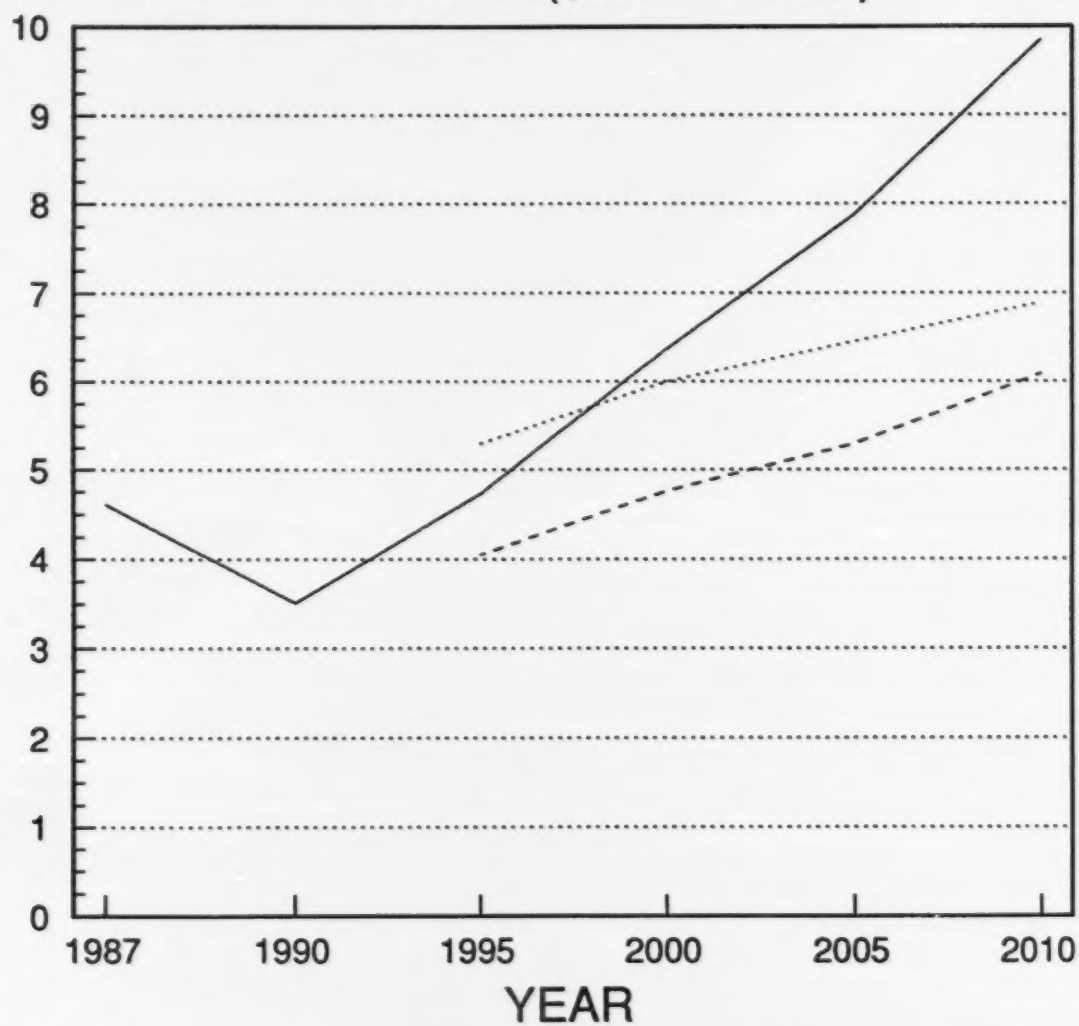
DELIVERED GAS PRICE (\$1988/MMBtu)



NAPAP/ARC EPA/HIGH EPA/LOW

FIG. 7 DISTILLATE OIL PRICE FORECAST
NAPAP/ARC & EPA BASE CASES
MODEL INPUTS

DELIVERED OIL PRICE (\$1988/MMBtu)

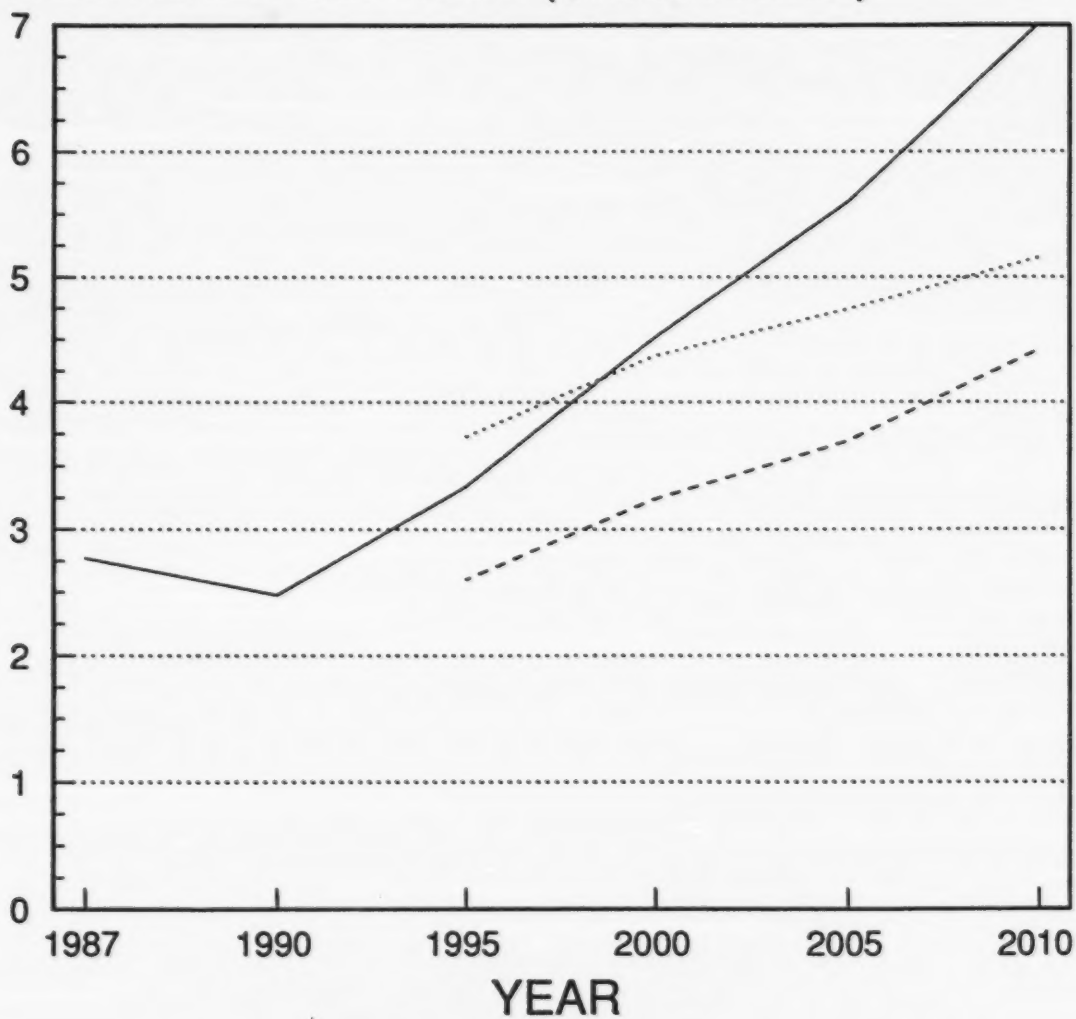


NAPAP/ARC EPA-HIGH EPA-LOW

FIG. 8 RESIDUAL OIL PRICE FORECAST

NAPAP/ARC & EPA BASE CASE
MODEL INPUTS

DELIVERED OIL PRICE (\$1988/MMBtu)

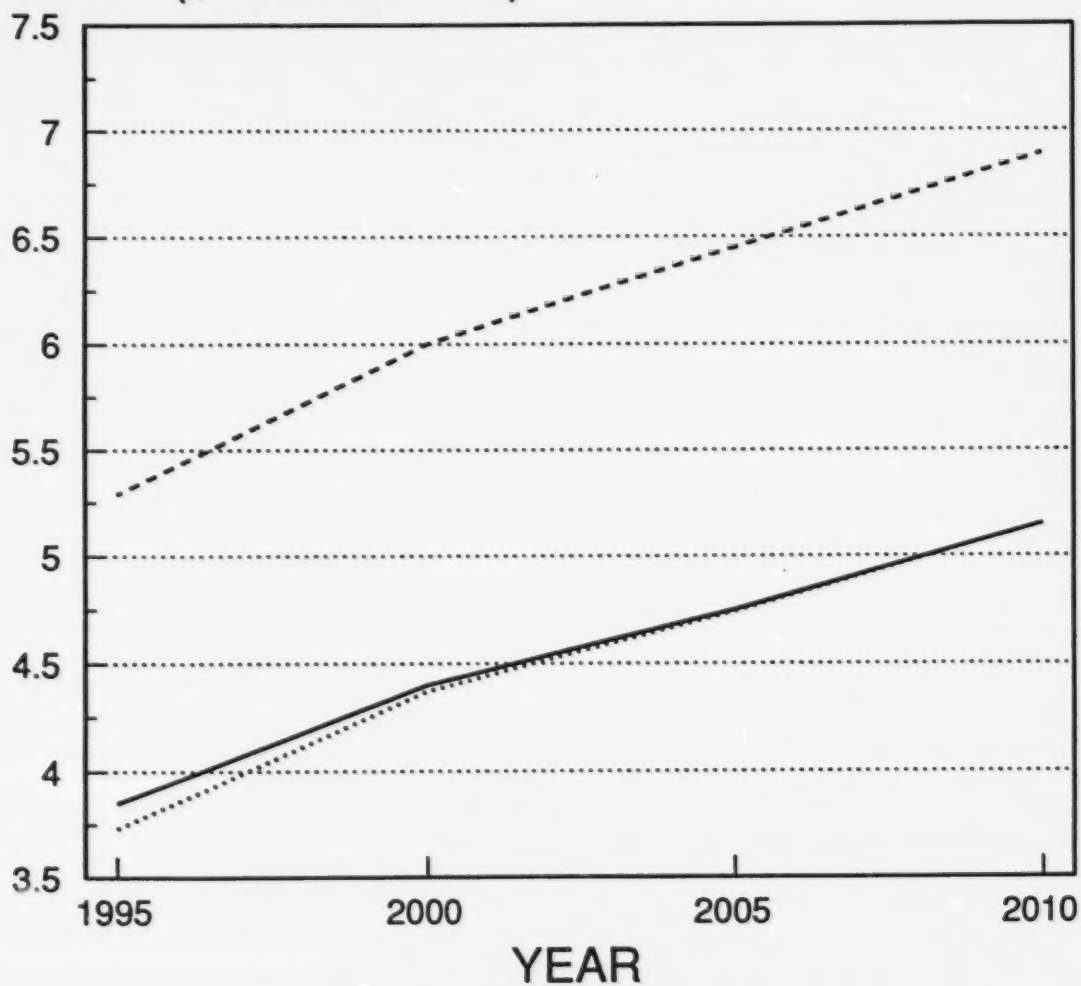


NAPAP/ARC EPA/HIGH EPA/LOW

— — —

FIG. 9 EPA LOW EMISSIONS CASE
GAS & OIL PRICE FORECAST
MODEL INPUTS

PRICE (\$1988/MMBTU)



NATURAL GAS DISTILLATE OIL RESIDUAL OIL

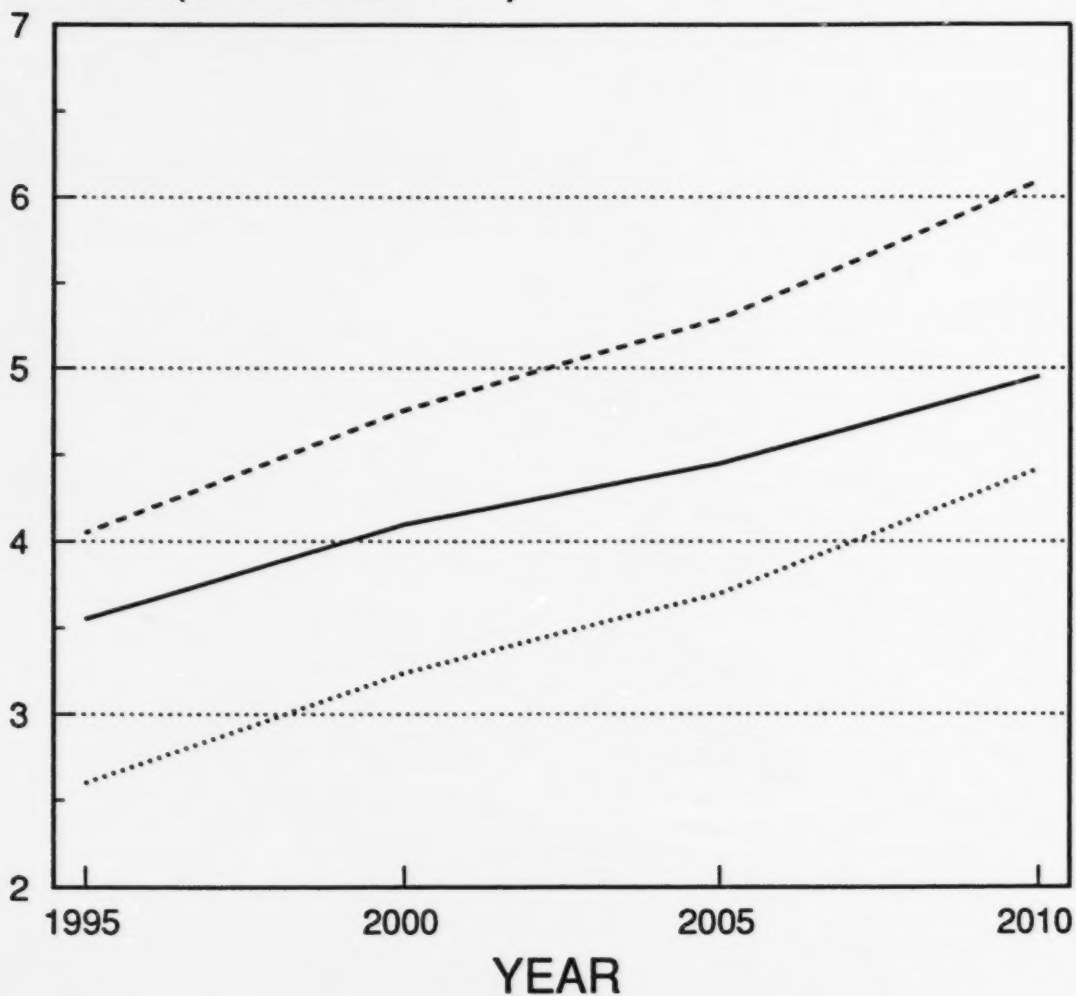
—

- - -

.....

FIG. 10 EPA HIGH EMISSIONS CASE
GAS & OIL PRICE FORECAST
MODEL INPUTS

PRICE (\$1988/MMBTU)

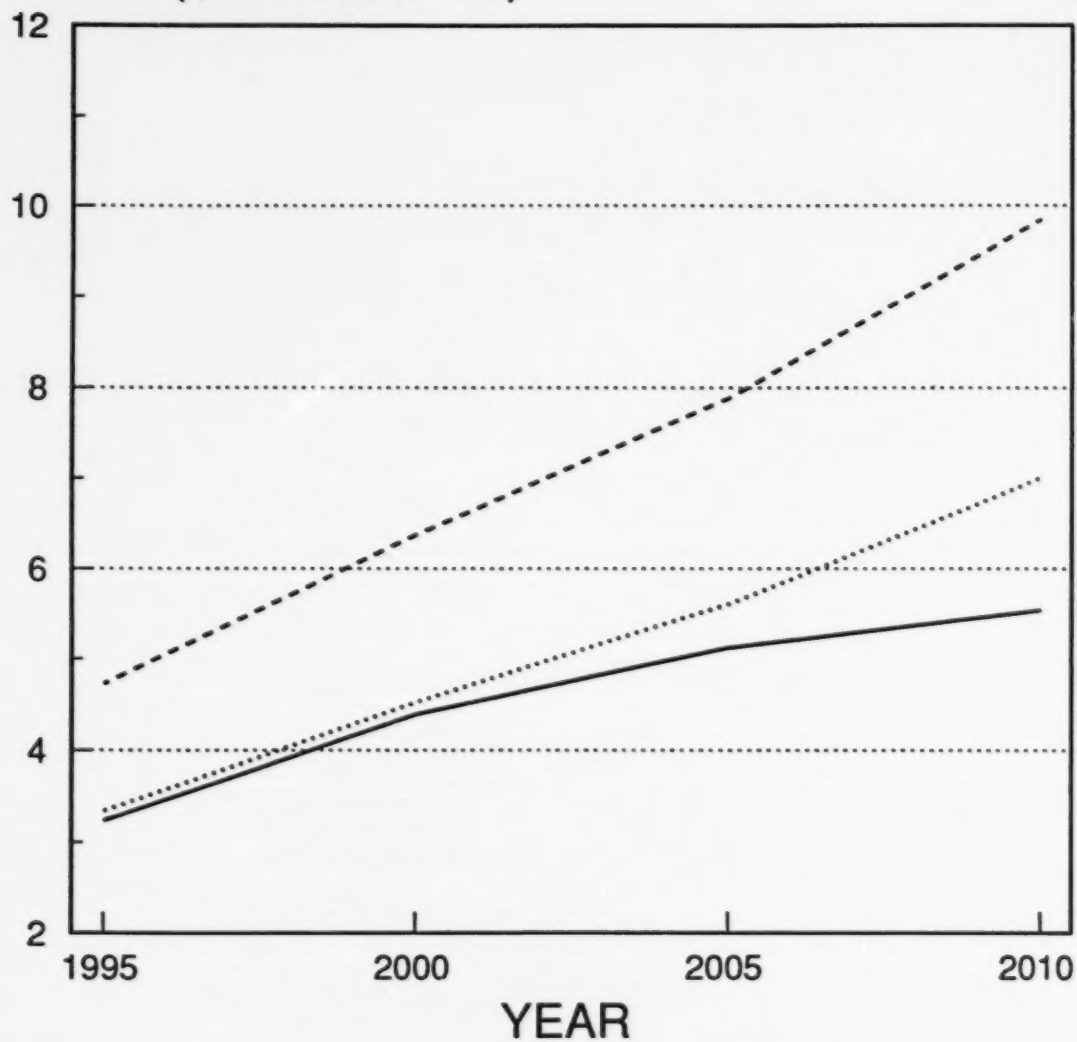


NATURAL GAS DISTILLATE OIL RESIDUAL OIL

— - - -

FIG. 11 NAPAP ANALYSIS REFERENCE CASE
GAS & OIL PRICE FORECAST
MODEL INPUTS

PRICE (\$1988/MMBTU)



NATURAL GAS DISTILLATE OIL RESIDUAL OIL

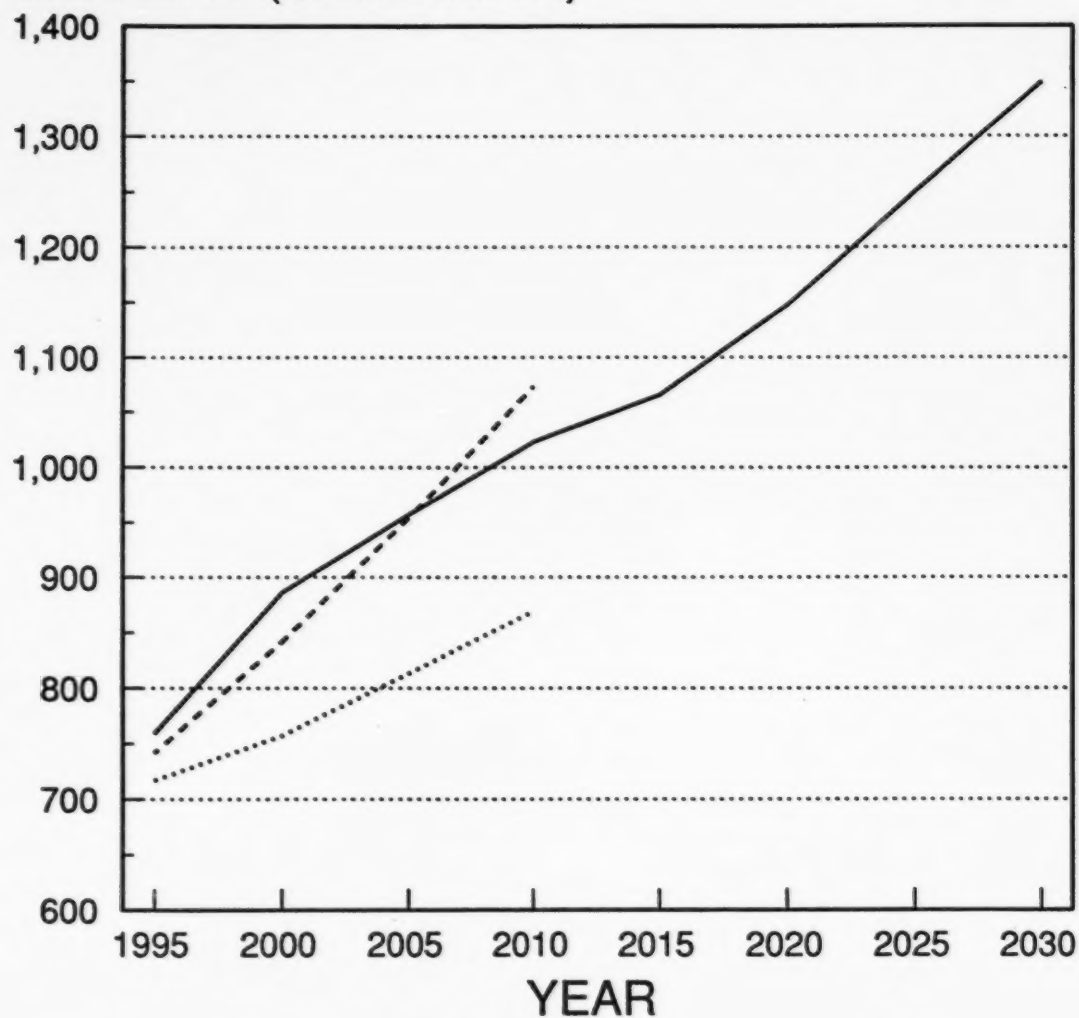
—————

- - - - -

.....

**FIG. 12 UTILITY GENERATING CAPACITY
MODEL OUTPUTS**

CAPACITY (GIGAWATTS)

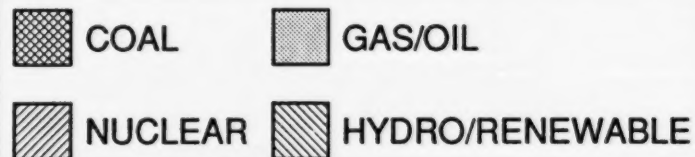
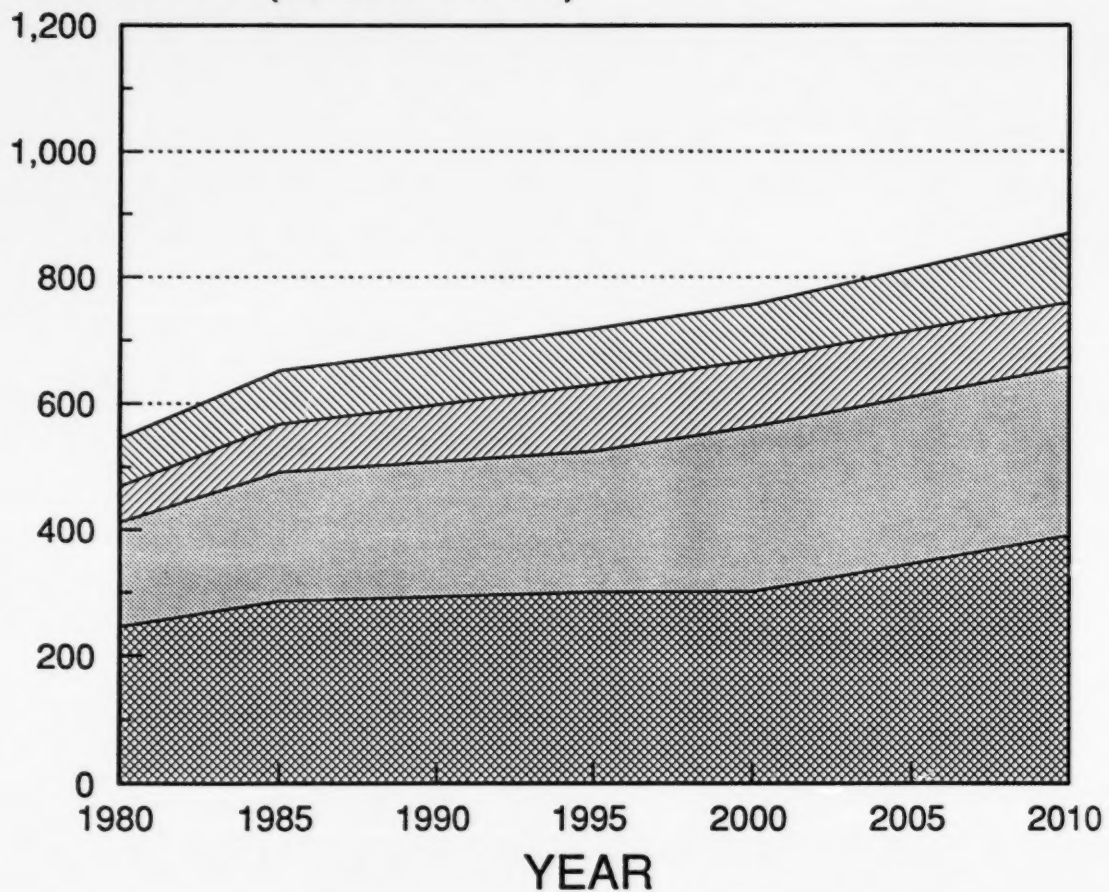


EPA/LOW CEUM MODEL	EPA/HIGH CEUM MODEL	NAPAP/ARC AUSM MODEL
.....	-----	————

FIG. 13 UTILITY GENERATING CAPACITY

MODEL OUTPUTS WITH
EPA/LOW INPUTS

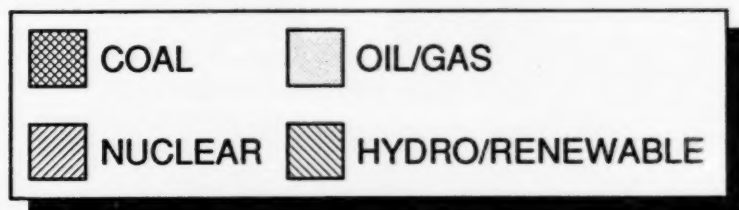
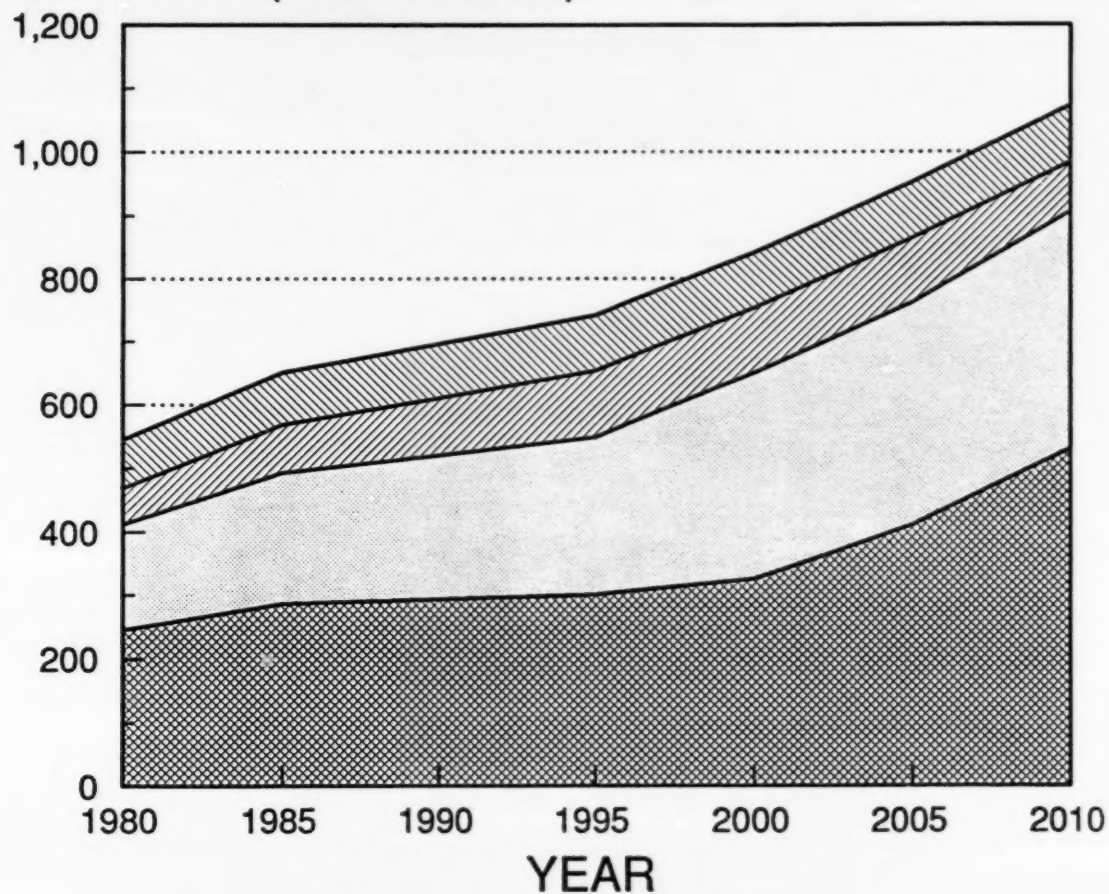
CAPACITY (GIGAWATTS)



CEUM MODEL

FIG. 14 UTILITY GENERATING CAPACITY
MODEL OUTPUTS WITH
EPA/HIGH INPUTS

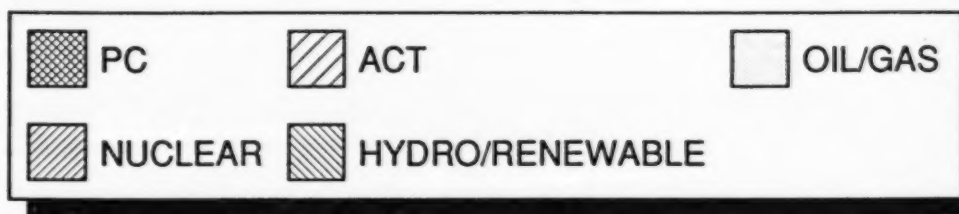
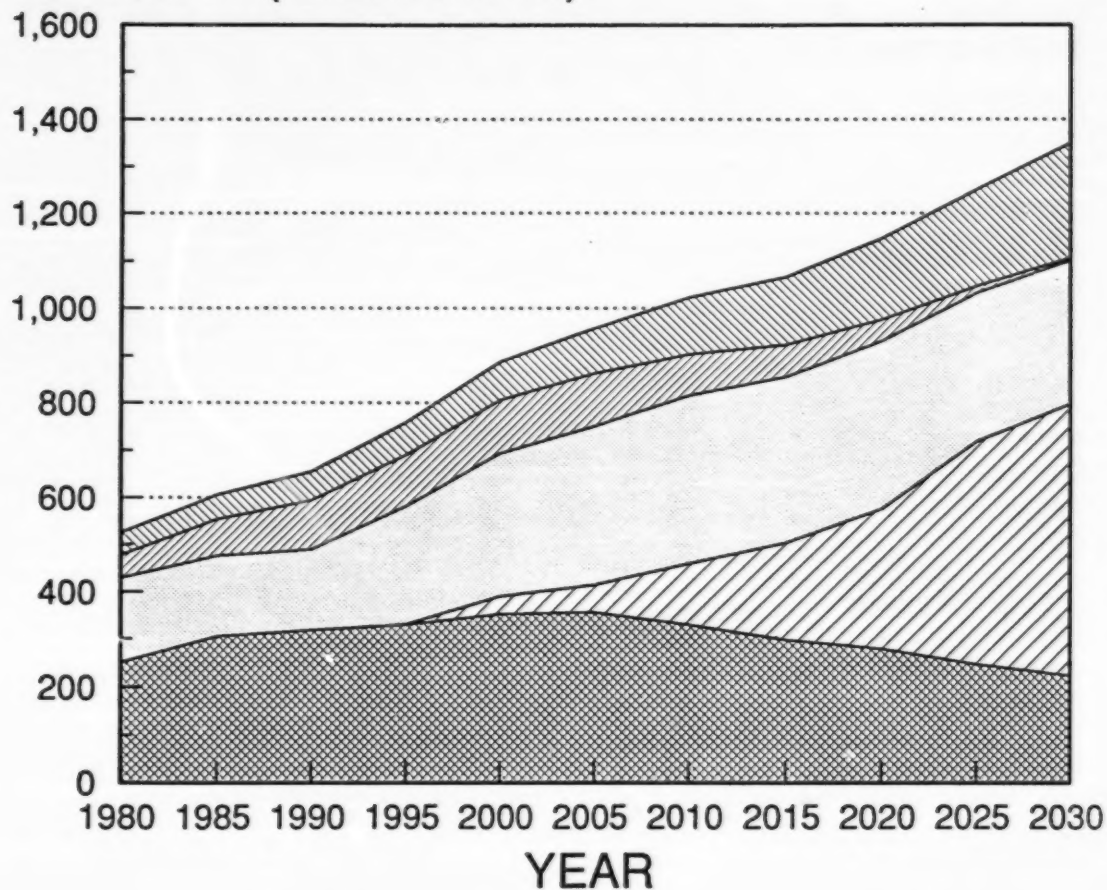
CAPACITY (GIGAWATTS)



CEUM MODEL

FIG. 15 UTILITY GENERATING CAPACITY
MODEL OUTPUTS WITH
NAPAP/ARC INPUTS

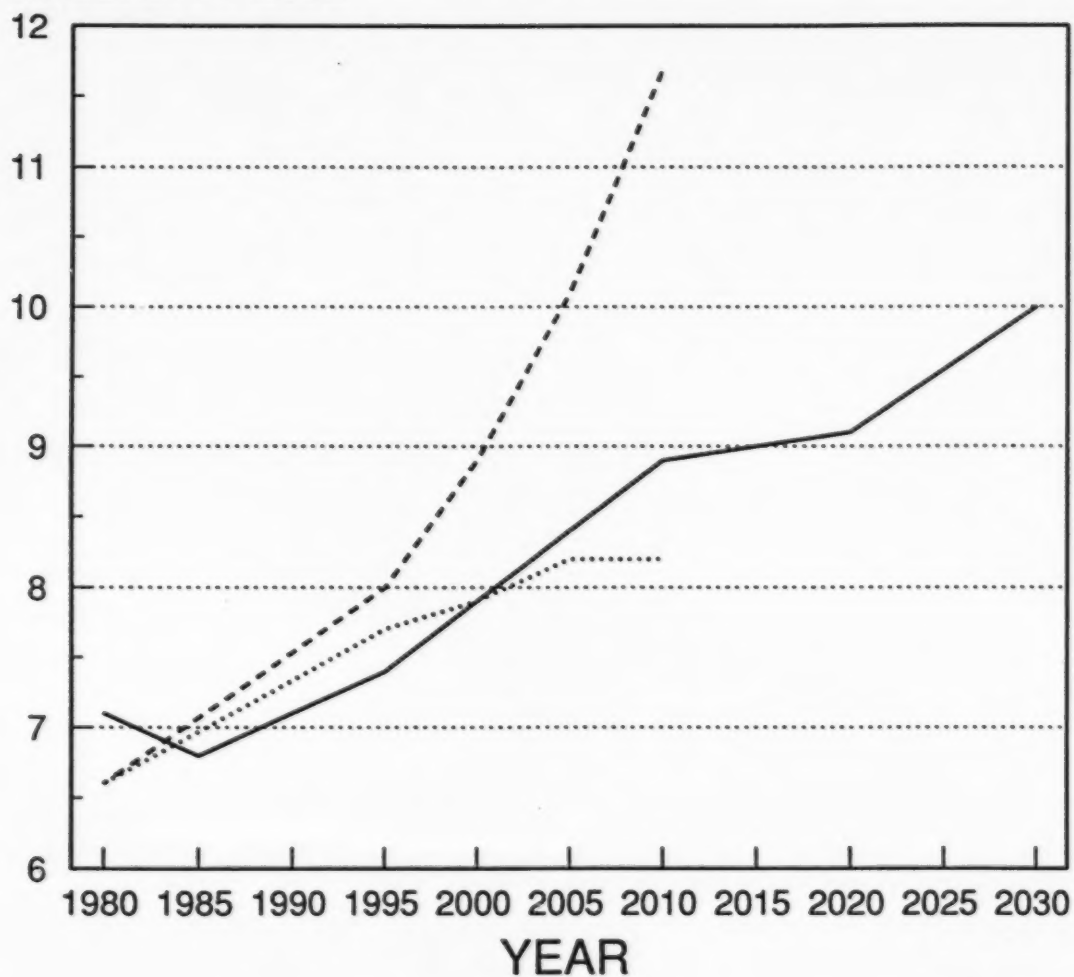
CAPACITY (GIGAWATTS)



AUSM MODEL

FIG. 16 UTILITY NO_x EMISSIONS
MODEL OUTPUTS

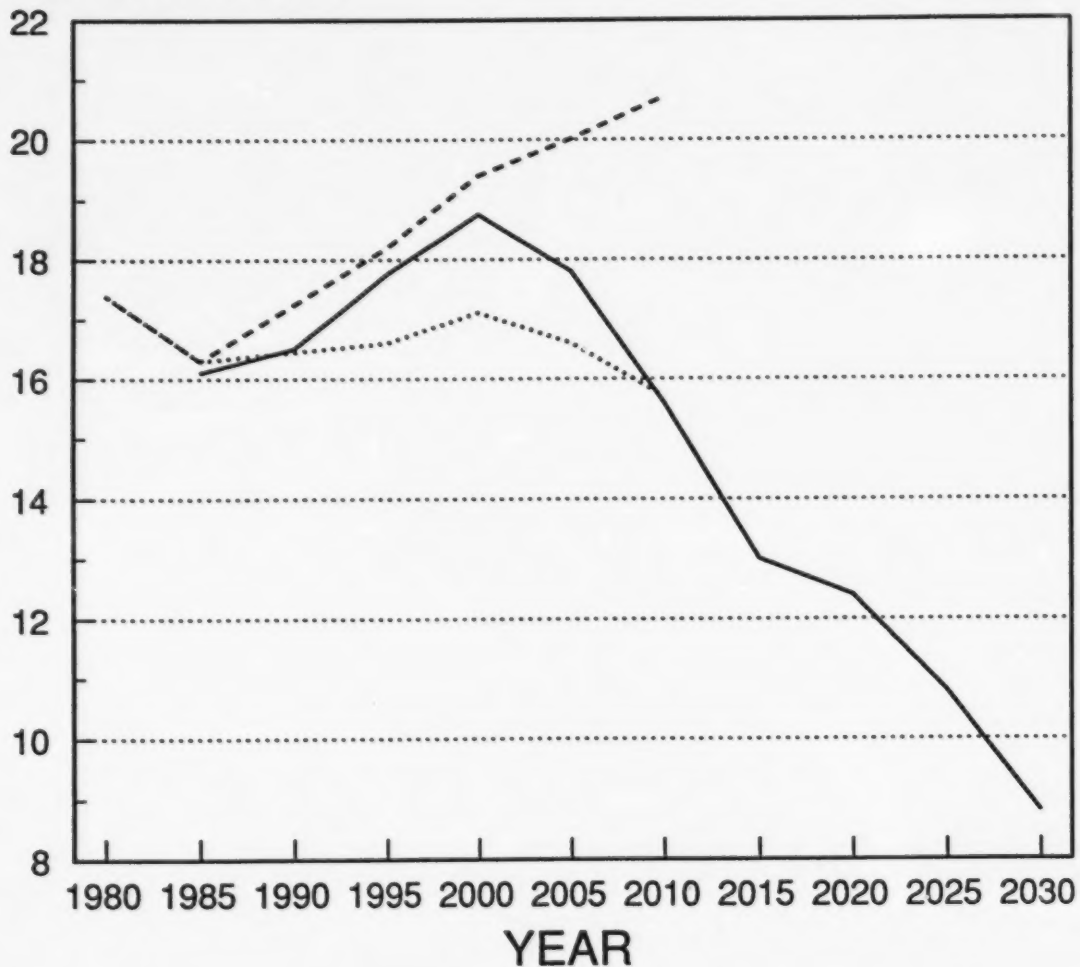
MILLION TONS



EPA/HIGH CEUM MODEL	NAPAP/ARC AUSM MODEL	EPA/LOW CEUM MODEL
-----	————	

FIG. 17 UTILITY SO_x EMISSIONS
MODEL OUTPUTS

MILLION TONS

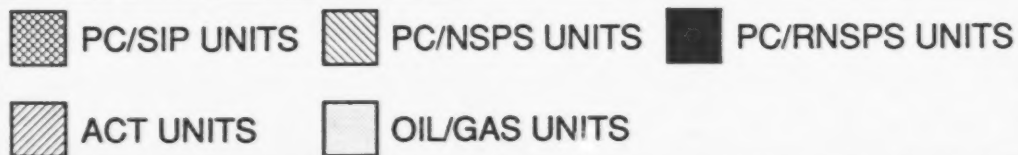
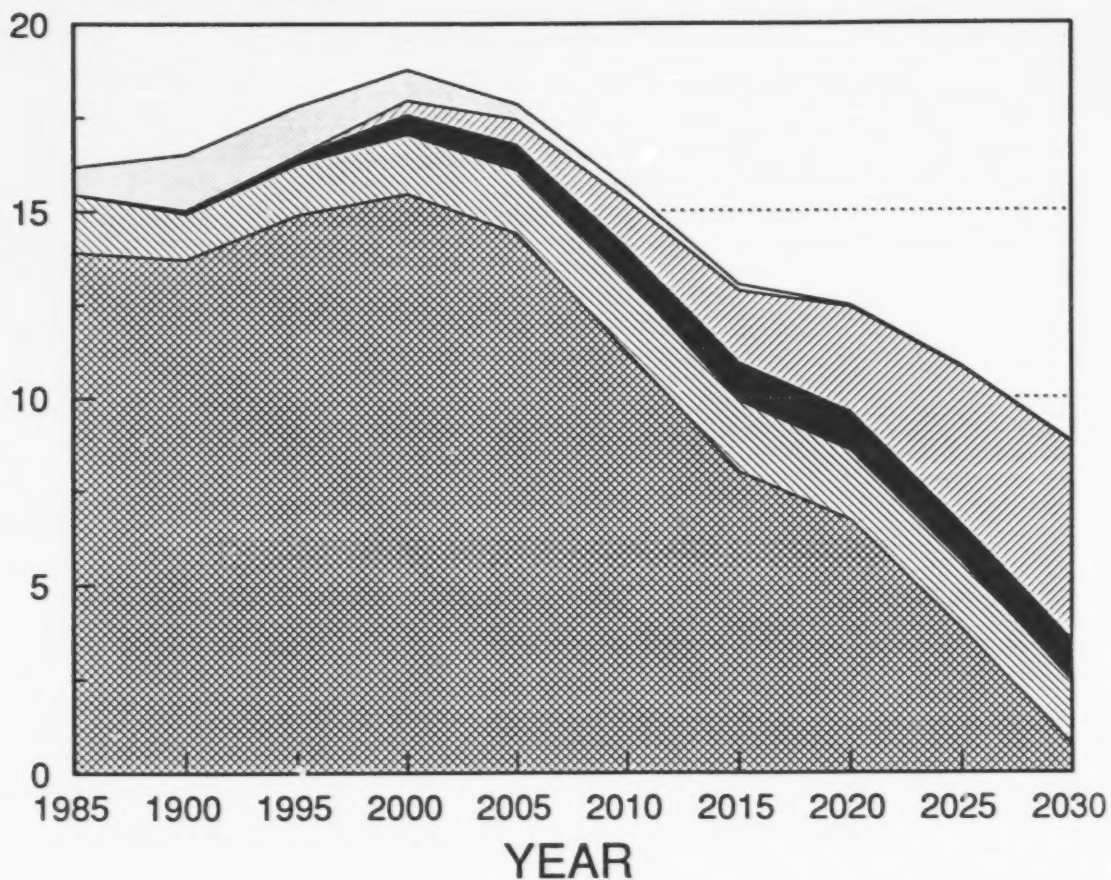


EPA/HIGH CEUM MODEL	NAPAP ANALYSIS AUSM MODEL	EPA/LOW CEUM MODEL
-----	————	

FIG. 18 SO_x EMISSION DISTRIBUTION

MODEL OUTPUTS WITH
NAPAP/ARC INPUTS

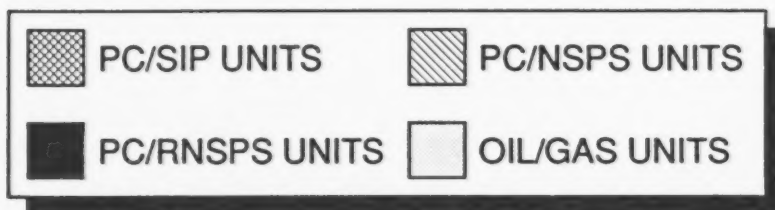
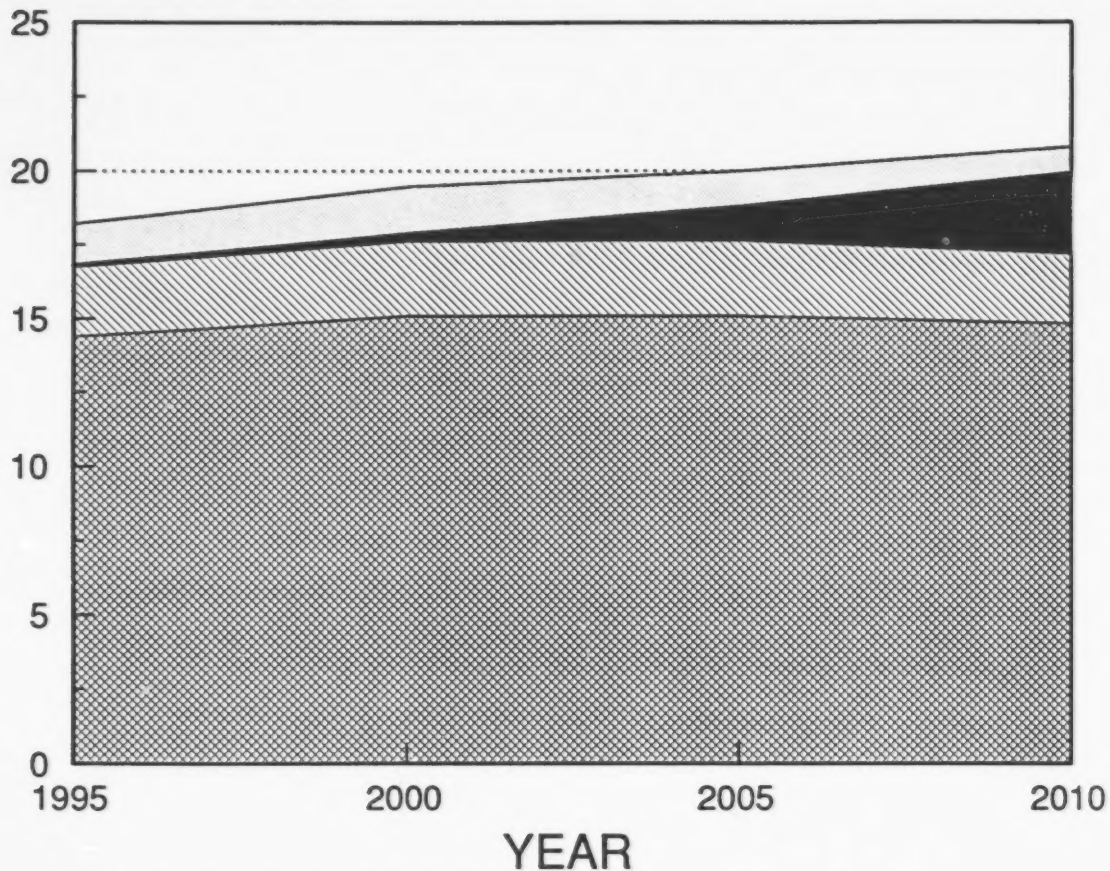
MILLION TONS



AUSM MODEL

FIG. 19 SO_x EMISSION DISTRIBUTION
MODEL OUTPUTS WITH
EPA/HIGH EMISSIONS INPUTS

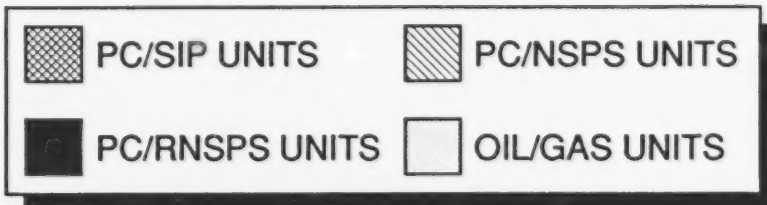
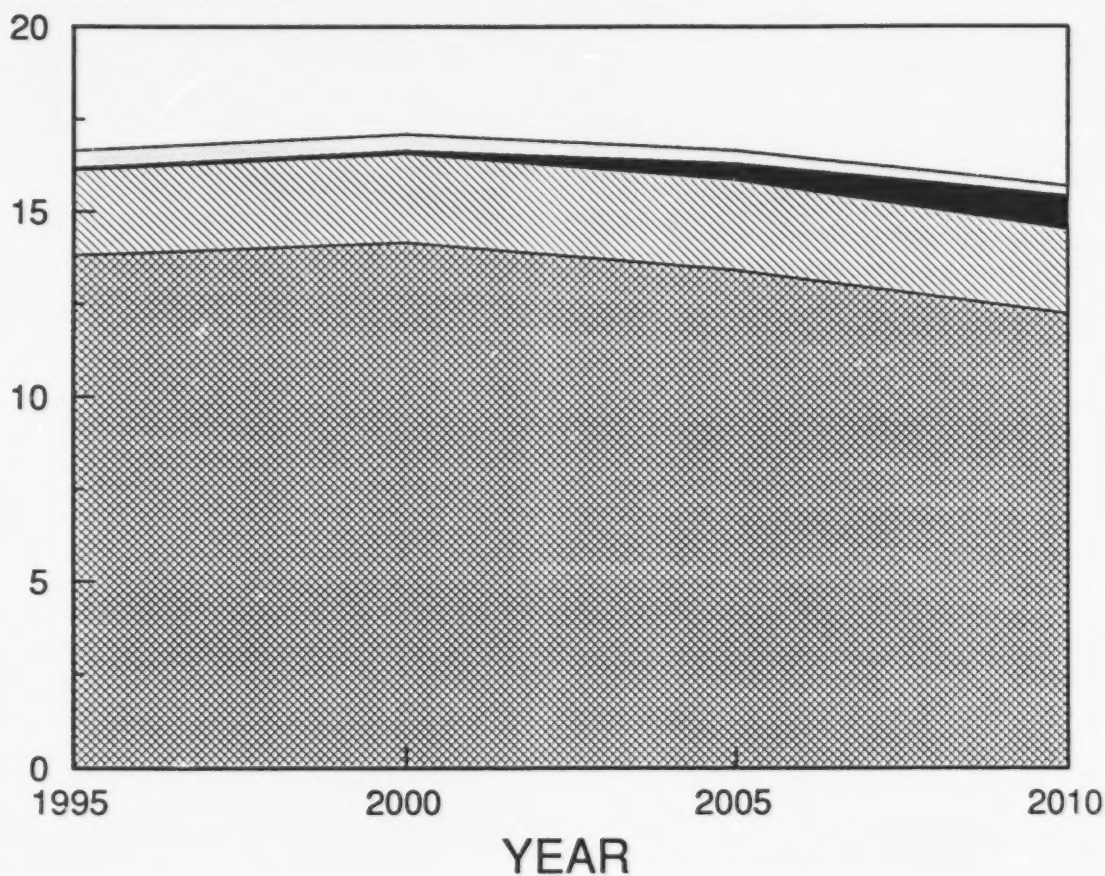
MILLION TONS



CEUM MODEL

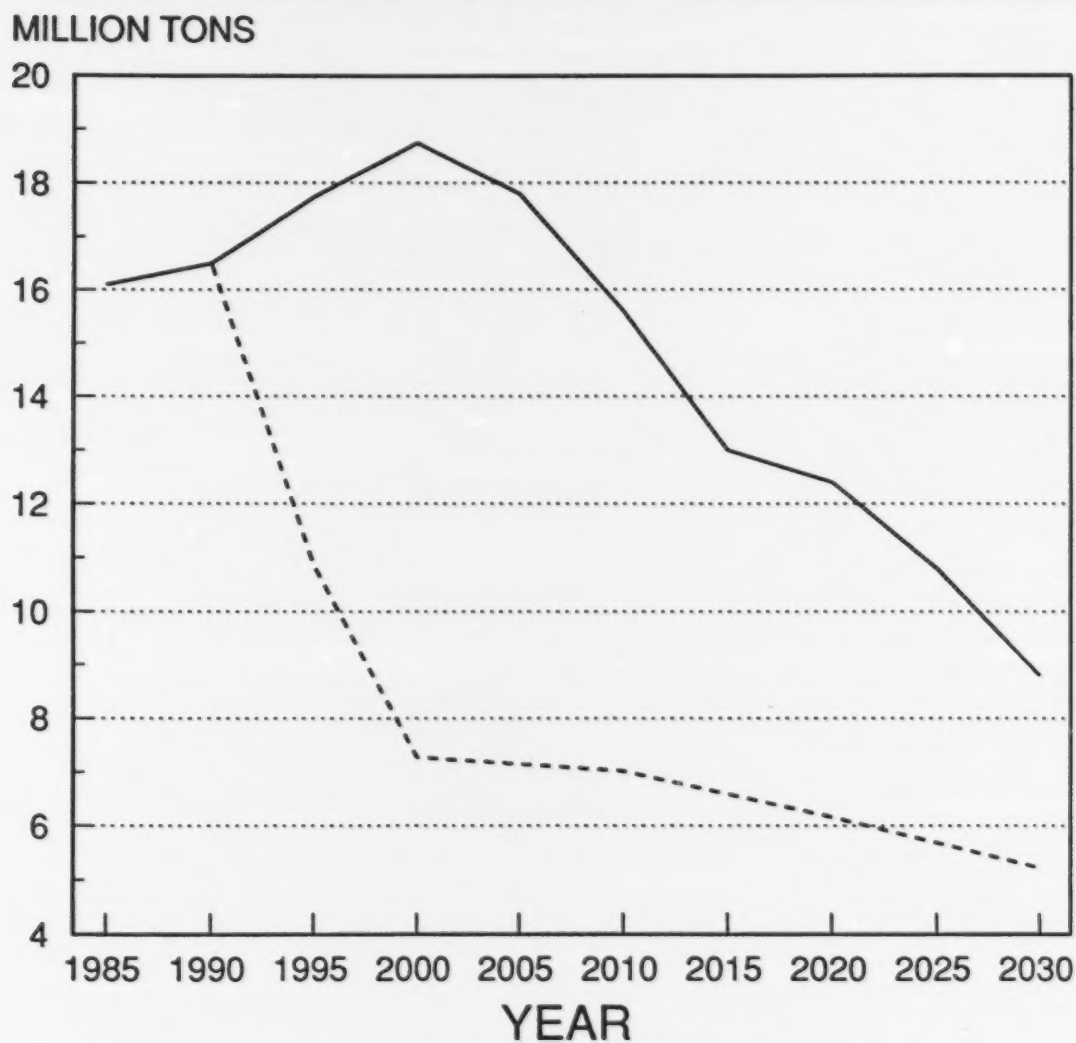
FIG. 20 SO_x EMISSION DISTRIBUTION
MODEL OUTPUTS WITH
EPA/LOW EMISSIONS INPUTS

MILLION TONS



CEUM MODEL

FIG. 21 SO_x EMISSIONS
TEN MILLION TON SO_x REDUCTION & NAPAP/ARC INPUTS
(PRELIMINARY)



BASE CASE REDUCTION CASE

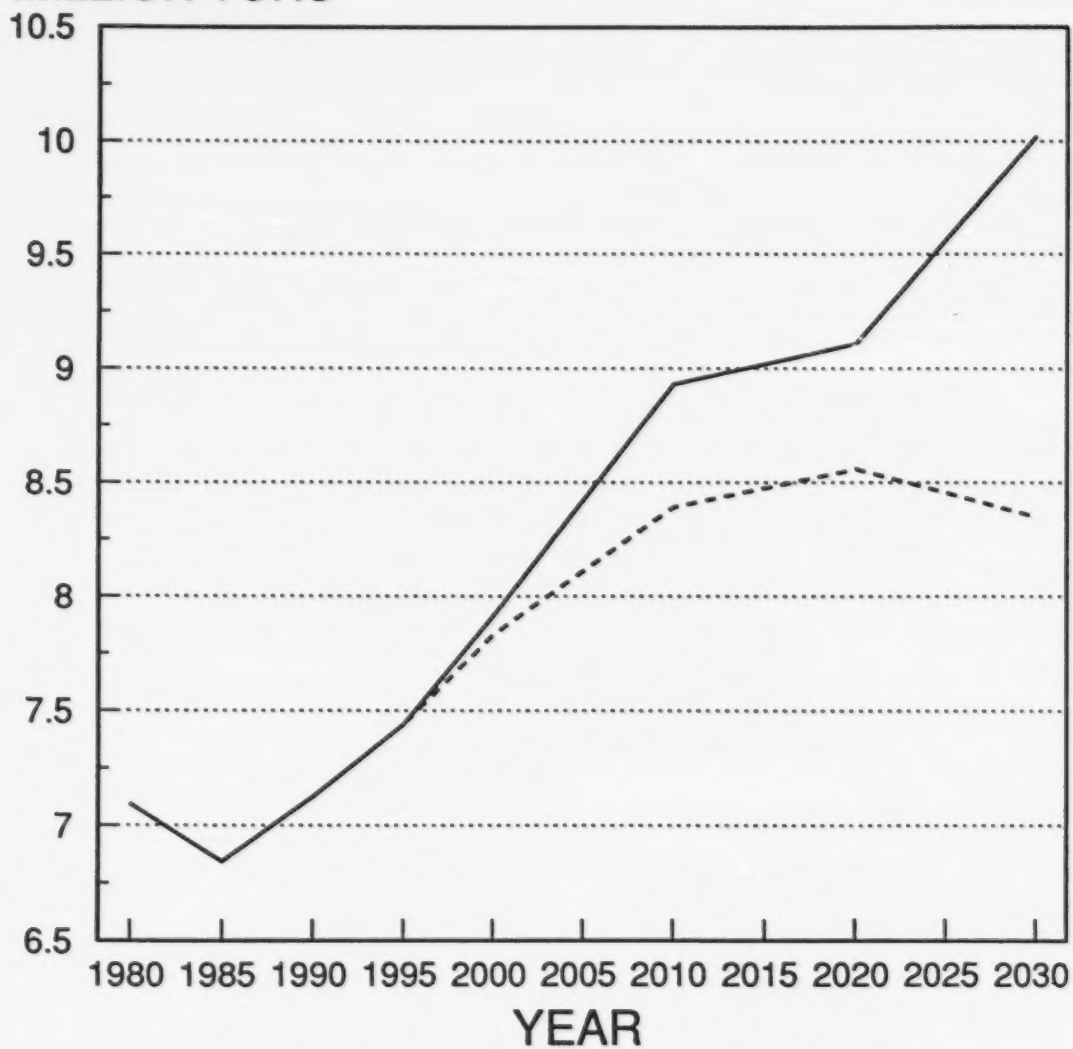
—

- - -

AUSM MODEL

FIG. 22 NO_x EMISSIONS
TEN MILLION TON SO_x REDUCTION & NAPAP/ARC INPUTS
(PRELIMINARY)

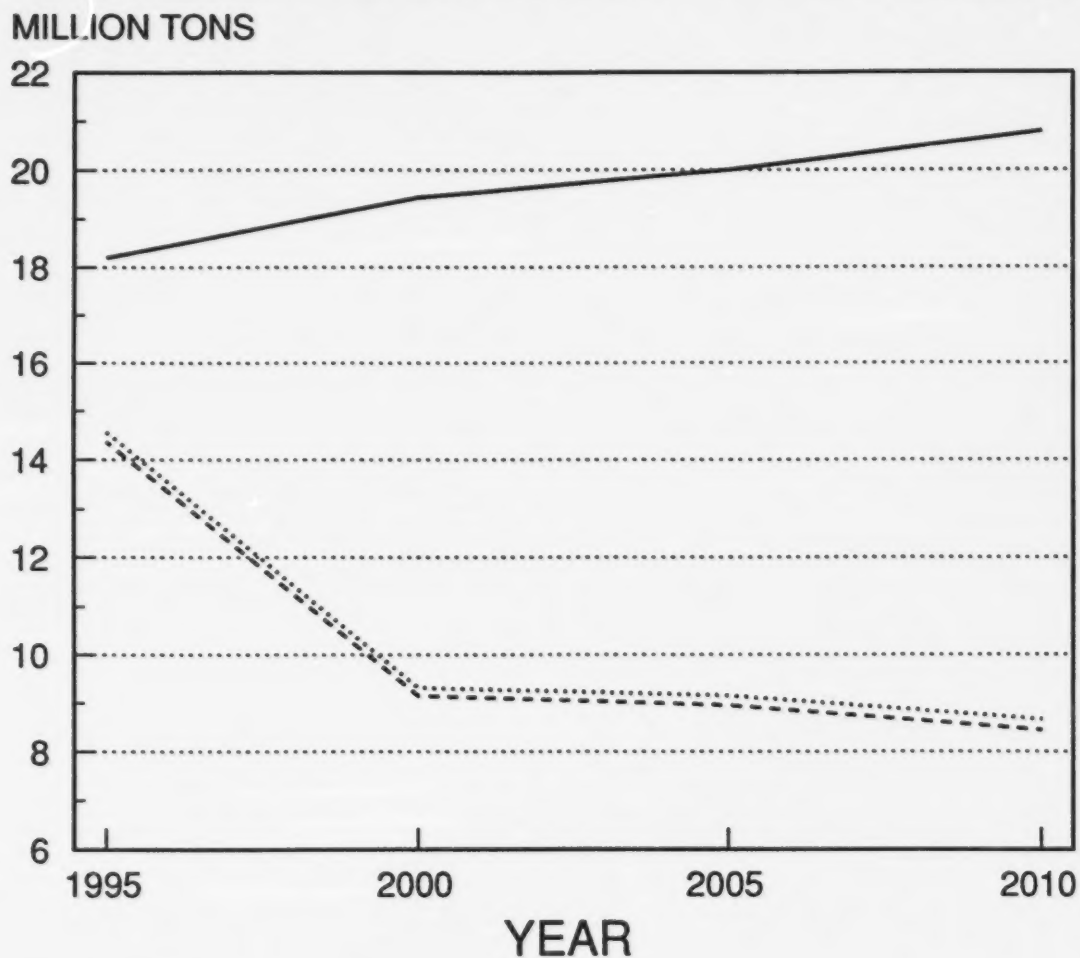
MILLION TONS



BASE CASE REDUCTION CASE

————

FIG. 23 SO_x EMISSIONS
TEN MILLION TON SO_x REDUCTION SCENARIO
EPA HIGH EMISSIONS BASE CASE MODEL INPUTS

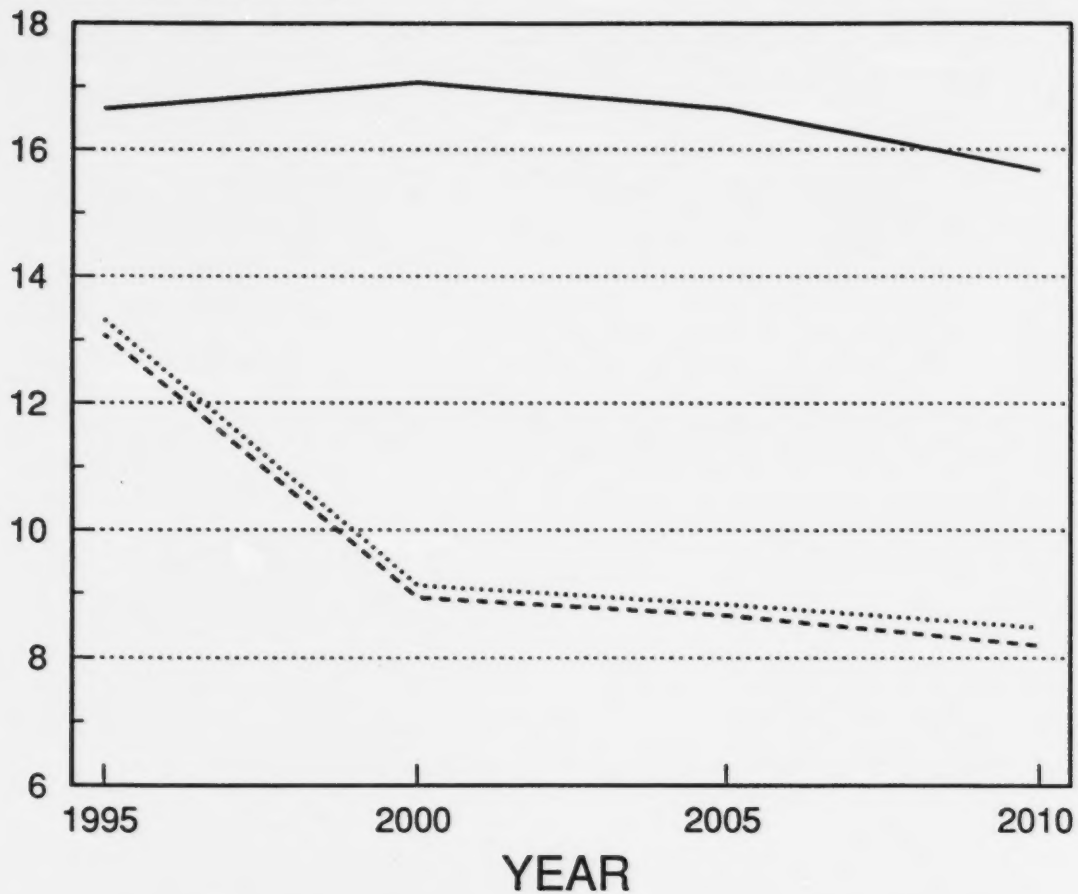


BASE CASE	REDUCTION CASE SYSTEM	REDUCTION CASE INTERSTATE
—	- - - - -	

CEUM MODEL

FIG. 24 SO_x EMISSIONS
TEN MILLION TON SO_x REDUCTION SCENARIO
EPA LOW EMISSIONS BASE CASE MODEL INPUTS

MILLION TONS

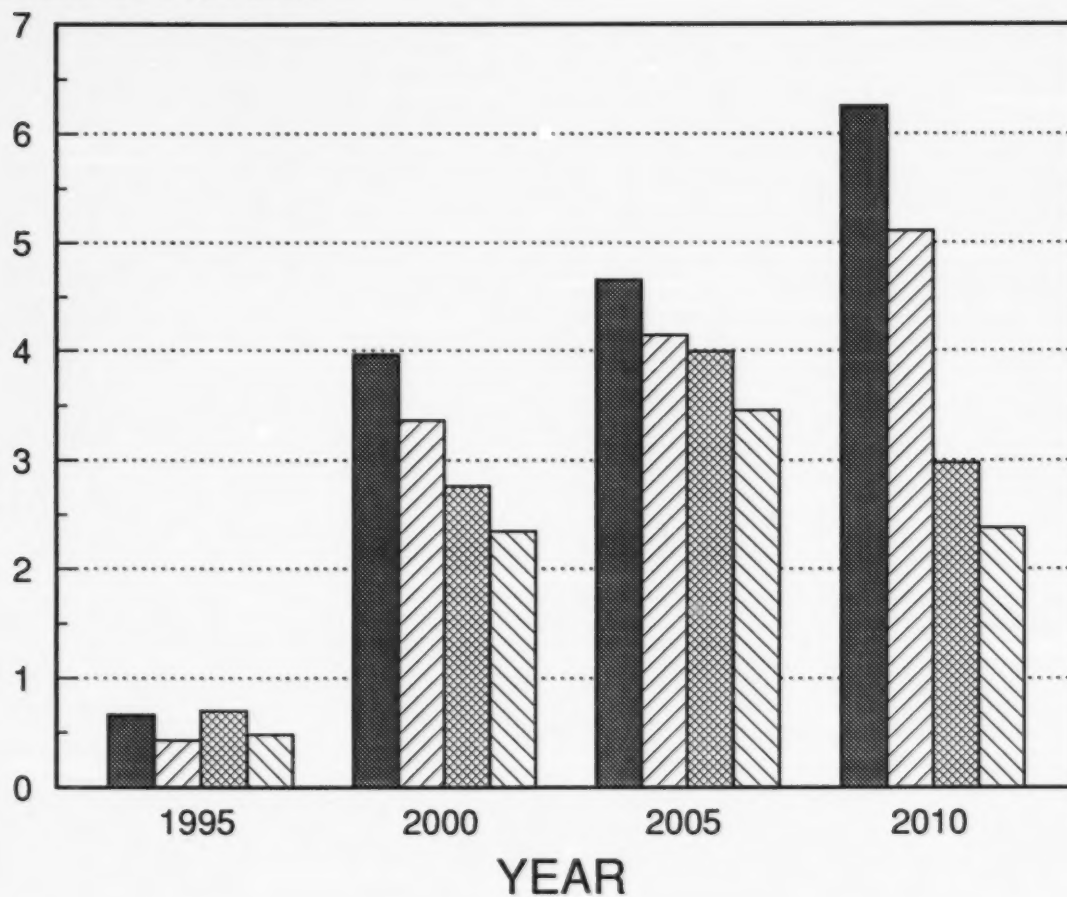


BASE CASE	REDUCTION CASE SYSTEM	REDUCTION CASE INTERSTATE
————	-----	

CEUM MODEL

FIG. 25 CHANGE IN ANNUAL LEVELIZED COSTS
SO_x EMISSIONS ALLOWANCE TRADING
SYSTEM-WIDE AND INTERSTATE TRADES

BILLION \$1988



CEUM MODEL

FIG. 26 MAJOR BUYERS AND SELLERS OF SOX ALLOWANCES

